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FINAL PROJECT REPORT

WIND INTEGRATION STUDY FOR THE SACRAMENTO MUNICIPAL UTILITY DISTRICT

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Prepared by: EnerNex Corporation

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- Cliff Murley
- Brad Dommer
- Sarah Majok
- Yong Cai

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PREFACE

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Wind Integration Study for the Sacramento Municipal Utility District is the final report for the SMUD ReGen project (contract number 500-00-034) conducted by EnerNex Corporation. The information from this project contributes to Energy Research and Development Division's Renewable Energy Technologies Program.

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ABSTRACT

This project addressed general questions regarding very specific prospective wind generation development scenarios at the Sacramento Municipal Utility District. The focus of the report includes: developing a wind generation model and multiple wind scenarios; developing models for the Sacramento Municipal Utility District system in the focus study of 2011; calculating an equivalent capacity value for wind generation for the Sacramento Municipal Utility District; high-resolution system and wind simulation for estimating incremental reserve requirements due to wind generation in the Sacramento Municipal Utility District control area; hourly dispatch simulations to assess the cost incurred by the Sacramento Municipal Utility District for managing wind generation; a wind generation technology overview and considerations for interconnection; and training aids and tools for Sacramento Municipal Utility District system operators.

Keywords: Wind generation model, turbine, renewable energy, wind simulation, renewable energy goals, SMUD

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EXECUTIVE SUMMARY

Introduction

Electric utilities must have sufficient generating capacity to meet peak demand in order to maintain high levels of power system reliability. Planning for adequate generating capacity as much as 20 years in advance is a critical activity for electric utilities and regional reliability organizations given the long lead times for developing supply resources and the relative inflexibility of demand.

Wind generation cannot be controlled or precisely predicted. Energy from wind generating facilities must be taken "as delivered," which necessitates using other controllable resources to keep the demand and supply of electric energy in balance. The capacity value of wind plants for long-term energy planning analyses is a topic of significant discussion in the wind and electric power industries. Wind generation can make a calculable contribution to system reliability despite the fact it cannot be directly dispatched like most conventional generating resources, but the capacity value of wind and the appropriate method for its determination need to be better understood.

Wind generation is primarily a source of electric energy since its output cannot be practically dispatched to a specified level at any given hour. Because of this apparent limitation, assigning a "capacity value" of zero to wind generation would seem appropriate. However, any of the conventional analytical methods used to assess power system reliability can demonstrate that some non-zero percentage of a given amount of wind generation can be "counted on" to meet load demands. The magnitude of the contribution will be a function of several factors, including the nature of the wind resource and its correspondence with system load patterns, and the types and reliability of conventional supply resources comprising the system.

The Sacramento Municipal Utility District (SMUD) was interested in significantly increasing its wind generation capacity but needed to understand how the effects of increased wind capacity would affect power supply and grid reliability.

Project Purpose

This project addressed general questions regarding very specific prospective wind generation development scenarios at the Sacramento Municipal Utility District. The goals of the project included:

- Developing the Wind Generation Model based upon scientific meteorological approach and defining appropriate scenarios for wind development.
- Developing models for the SMUD system to define the 2011 target study system and build system reliability and unit commitment models.
- Calculating the capacity value of wind generation for SMUD using a traditional Loss of Load Expectation reliability analysis, and an Effective Load Carrying Capability analysis.

- Estimating incremental reserve requirements and high-resolution simulation due to wind generation in the SMUD control area through statistical means.
- Performing hourly dispatch simulations to assess the cost incurred by SMUD for managing wind generation using a unit commitment approach.
- Reviewing wind generation technology and considerations for interconnection.
- Investigating training aids and tools for SMUD system operators.

Project Results

This project examined the increase in fast regulation requirements, integration costs, and equivalent capacity factors on SMUD 's electrical grid for four different levels of wind generation:

- Case 1: Expansion of the existing Solano facility to 102 megawatts (MW).
- Case 2: Further expansion of Solano to 250 MW.
- Case 3: Addition of 200 MW at a geographically remote location for a total installed wind generation capacity of 450 MW.
- Case 4: Further expansion at geographically remote sites for a total wind generation capacity of 850 MW.

The outcomes of the project included the following:

- Fast responding regulation capacity equal to some multiple of the standard deviations would be necessary to compensate for almost all of the load fluctuations. Integration studies with other control areas have found this factor to range up to five.
- The average of five times the standard deviation of the SMUD load regulation characteristic was approximately 18 megawatts MW for the 14 days analyzed. The average as a percentage of peak load was 1.15 percent. Therefore, the researchers concluded that the minimum REGUP and REGDOWN capacity for the SMUD control area is up to 18 MW. REGUP in the morning would be higher to account for two-thirds of the expected load pick up over the hour, with REGDOWN set to 18 MW. In the evening as the load ramps down, REGDOWN would again be two-thirds of the expected hourly decrease, with REGUP at 18 MW.
- Applying the findings from the National Renewable Energy Laboratory (NREL) measurement program and subsequent analysis, the standard deviation of the regulation characteristic for each of the scenarios would be 1 MW, 1.6 MW, 2.12 MW, and 2.91 MW for the four cases, respectively. The regulation characteristic of the combination can be calculated from the statistics of the individual characteristics if the regulation characteristics of the individual subsets are truly uncorrelated. The effects on the system fast requirement were determined for each of the four cases using this method. The results showed that the fast

regulation requirement increased to as much as 5.1 MW with 850 MW of wind generation.

- Additional requirements for hourly variability and schedule deviation could raise the operating reserve requirements as high as 200 MW for 850 MW of wind.
- The study also estimated the integration costs for the different cases under several scenarios.
- The study found lower penetrations of wind generation have only a small impact on fast regulation requirements, but begin to dominate as the penetration increases.

The authors determined that the integration cost dropped significantly with the wind penetration level. At first, this seemed counterintuitive since it would seem likely that more wind would require less efficient commitment to handle the uncertainty and variability in the wind energy delivery. One aspect of lowering the effect of higher wind penetrations was increased geographic diversity. Cases 1 and 2 were concentrated scenarios with all of the turbines in a relatively small area, and were affected by essentially the same meteorology at the same time. In Cases 3 and 4, the wind plants were scattered over a much greater geographic area. This tended to smooth the wind because while one site may have low wind another may have high wind.

Capacity factor calculation was not sufficient to judge the benefits of adding wind generation to a certain system. Adding wind generation leads to an increase in the overall generation system adequacy. This increase in system reliability was quantified by calculating the Equivalent Load Carrying Capability. This value represented the extra amount of load–as a percentage of installed wind generation capacity–that the generating system could supply due to the addition of new wind generation, while still maintaining the same level of generation reliability Loss of Load Expectation of 24 hours per 10 years.

The hourly dispatch simulations task of this study provided a snapshot of best estimates for generation resources, forecast load conditions, and expected market rules. Each of these aspects could have a strong influence on the results of operations and integration cost calculations and the ultimate viability of the system with a given amount of integrated wind.

It is well known that wind forecast error strongly influences the outcome of wind integration cost calculations. This study did not include sensitivity analysis to the forecast error and how improved forecasting might affect the results. Better estimates of the operational and integration costs can be made as state-of-the-art forecasting techniques improve forecast accuracy.

This study did not model any possible correlation between wind and wind forecast error and/or load forecast error. There was empirical evidence that these wind forecast errors and load forecast errors were inversely related and additional analysis of this phenomena may be warranted.

This report includes a brief investigation of hedging strategy against energy shortfalls due to lower wind than forecast, but possible strategies to minimize costs warrant further investigation. This study also looked at a basic operational model for the proposed Iowa Hill pumped storage facilities and how those facilities could be used to optimally integratd wind energy. SMUD should also investigate additional approaches for optimal operational strategies for Iowa Hill.

Project Benefits

The results of this project will provide initial insights into the impact of significant wind generation on the operation of the SMUD control area, along with approaches for reducing or managing those impacts. From this starting point, it is likely that as the amount of wind generation increases, SMUD system operators and planners would develop increasingly better strategies for accommodating the unique nature of wind generation over time.

The information gained in this study allows SMUD to evaluate wind generation expansion to meet its renewable portfolio goals while ensuring reliable and adequate energy delivery to its customers. SMUD planners now have an increased ability to determine the financial viability of wind generation projects. The uncertainty of wind generation has been reduced through assessing the whole picture, including cost of production, integration, fast regulation requirement, and effective capacity.

Other utilities can benefit from the study by replicating the methods used and learning from the results to better understand the effect of increasing wind generation on their control areas. This study was a necessary step toward increasing statewide wind-generated electricity. Furthermore, the report gives electricity planners the information needed to provide renewable energy to their customers without compromising energy supply or reliability.

Chapter 1: Introduction

Wind generation cannot be controlled or precisely predicted. While these attributes are not unique to wind generation, variability of the fuel supply and its associated uncertainty over short timeframes are more pronounced than with conventional generation technologies. Energy from wind generating facilities must be taken "as delivered", which necessitates the use of other controllable resources to keep the demand and supply of electric energy in balance.

Integrating wind energy involves the use of supply side resources to serve loads not served by wind generation and to maintain the security of the bulk power supply system. Conventional resources must then be used to follow the net of wind energy delivery and electric demand, and to provide essential services such as regulation and contingency reserves that ensure power system reliability. To the extent that wind generation increases the required quantity of these generating services, additional costs are incurred.

The high reliability of the electric power system is premised on having adequate supply resources to meet demand at any moment. In longer term planning, system reliability is often gauged in terms of the probability that the planned generation capacity will be sufficient to meet the projected system demand. It is recognized that conventional electric generating plants and units are not completely reliable–there is some probability that in a given future hour capacity from the unit would be unavailable or limited in capability due to a forced outage (e.g. mechanical failure). Even if the installed capacity in the control area exceeds the peak projected load, there is some non-zero probability that the available capacity might be insufficient to meet load demands in a given hour

The capacity value of wind plants for long term planning analyses is currently a topic of significant discussion in the wind and electric power industries. Characterizing wind generation to appropriately reflect the historical statistical nature of the plant output on hourly, daily, and seasonal bases is one of the major challenges. Several techniques that capture this variability in a format appropriate for formal reliability modeling have been proposed and tested. The lack of adequate historical data for the wind plants under consideration is an obstacle for these methods.

Any of these methods can show that wind generation does make a calculable contribution to system reliability despite the fact it cannot be directly dispatched like most conventional generating resources. The magnitude of that contribution and the appropriate method for its determination are important considerations.

The work reported here addresses these general questions for very specific scenarios of prospective wind generation development at the Sacramento Municipal Utility District (SMUD). The report outcomes are organized into sections corresponding to the original work scope defined for securing funding from the California Energy Commission. The report sections with their general focus and content include:

- **Task 1**: Developing the Wind Generation Model
- **Task 2**: Developing models for the SMUD system
- **Task 3**: Calculation of the capacity value of wind generation for SMUD
- **Task 4**: High-resolution simulation work, and estimating of incremental reserve requirements due to wind generation in the SMUD control area
- **Task 5**: Hourly dispatch simulations to assess the cost incurred by SMUD for managing wind generation
- **Task 6**: Wind generation technology overview and considerations for interconnection
- **Task 7**: Training aids and tools for SMUD system operators.

The project approach section of this document covers the all of these tasks with some discussion of the tools and methods used. Since each task was performed somewhat independently, the material may seem duplicative in some places and out of context in others to meet the needs of the standard report template.

For as much as is practical, approach information that is necessary for context of results will be presented in the outcomes section. In doing this the authors hope to minimize contextual confusion. References back to the approach section from the outcomes section will be frequent.

Chapter 2:
Project Approach

The objective of this project is to analyze the impacts of various levels of wind generation on ancillary service amounts and costs, SMUD control performance and system reliability, and the impacts on reserve requirements. Wind models will be developed for Solano and other high value wind sites and wind production simulations will drive the SMUD control area models. Due to the uncertainty around the long-term viability of SMUD's participation in the Participating Intermittent Resource Program (PIRP), the approach will be to develop SMUD control area models for two different operating regimes: (1) new wind is hard-wired to the SMUD control area, and (2) new wind is scheduled through PIRP. Under the Independent System Operator (ISO) PIRP regime, the project will need to model all current and forecast wind resources inside the ISO and the need for regulation and load following service and cost for the entire ISO. (Given the complexity of ISO operation and wind resources, some simplifying assumptions may be used for the SMUD project. The project should also prepare an interface to the upcoming California wind integration study and refine the study results once the California study is complete.) The various wind scenarios will also be simulated with and without the proposed Iowa Hill pumped storage project.

2.1 Task 1–Wind Model Definition

SMUD selected EnerNex Corporation of Knoxville, Tennessee, to perform the technical analysis for the project. The company has subcontracted with WindLogics from St. Paul, Minnesota, to provide expertise and modeling capability for development of the chronological wind generation data which is critical for the study.

2.1.1 Defining the MM5 Simulation Model

The methodology used for analysis of the technical and economic impacts managing wind generation in the SMUD control area is very dependent on a high-fidelity chronological representation of how wind generation would appear to system planners and operators.

Since the wind generation to be considered here is speculative, and potentially in locations where there is a dearth of historical wind speed measurement data, an alternate approach is necessary. In wind integration studies, the project team has employed an approach based on simulation of the meteorology in the region with physics-based models of the atmosphere, which is also the basis for weather forecasting. For this project, a meteorological simulation model known as MM5 is used.

This general approach is augmented in a couple of important ways:

1. The spatial and temporal resolution of the MM5 model is generally hourly, with a two-dimension (latitude and longitude–grid or cell size of 20 to 40 kilometers [km]). Better resolution around key wind resource areas is achieved by inserting

one or more nested grids into the model, increasing the spatial resolution to just a few kilometers.

2. The model is run for historical time periods. In weather forecasting, current observation data is used to initialize the model, and a picture of the weather going into the future is generated by simulation. Since atmospheric modeling is known to be a "chaotic" phenomenon, the simulated version of the weather may be different from what actually occurs, although it is still valid physically. By selecting historical years, archived observation data is continually fed into the model to keep it "tracking" the weather that did occur. This allows the simulation results to be validated against archived measurement data. Another benefit is that the meteorological data can be matched with historical electric system data (especially load) so that any correlations between these data sets due to common meteorology are preserved.

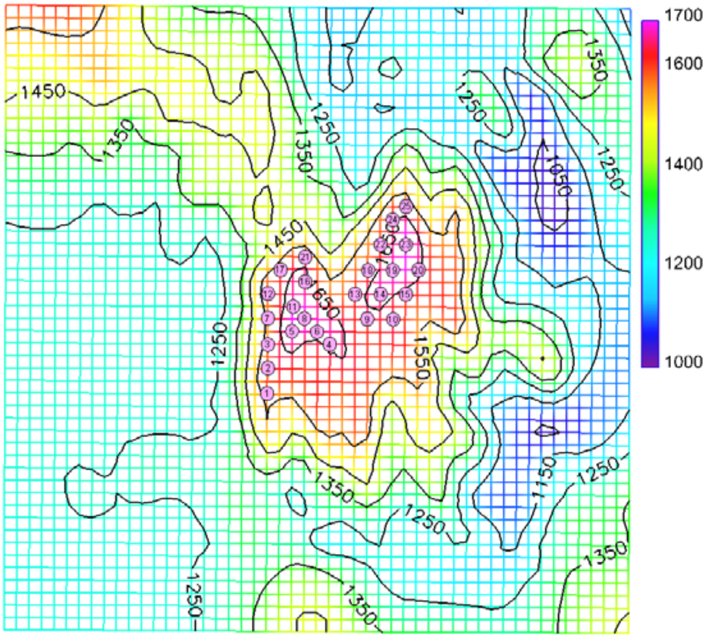
Two historical years–2003 and 2004–were simulated in the manner described above.

Figure 1 illustrates one of the "inner grids" created for the SMUD MM5 simulations. The grid dimensions in this case are 1 km by 1 km. The selection of inner grid size is a tradeoff between simulation time and resolution. Smaller grids increase the simulation time by an exponential factor of two (the vertical resolution of the base MM5 model is defined by 33 atmospheric "layers"; that granularity is retained for the SMUD simulations). Complex terrain, however, may dictate the use of smaller inner grids, which is the case for some of the wind resources areas selected by SMUD.

Those areas are depicted in Figure 2. They include the nearby Solano area, where SMUD currently has a 15 MW wind project operating, two locations in northern California, and two additional locations in southeastern Oregon.

Each area defines specific points at which wind speed time series data is to be extracted. The points are sometimes referred to as "proxy towers" since they represent imaginary meteorological monitoring facilities. During the MM5 simulation, weather variables including wind speed, direction, temperature, and pressure at 80 meters (m) above ground level (the assumed hub height for a commercial wind turbine) are periodically saved. For the SMUD simulations, meteorological data was saved at 10 minute intervals.

Figure 3 through Figure 7 show the location of each proxy tower or extraction point in the five regions of interest.


1700
1600
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1200
1000
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1650
1550
1250
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1150
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1350
1250
1350

Figure 1. Example inner grid layout for MM5 meteorological simulation

Source: EnerNex Corporation

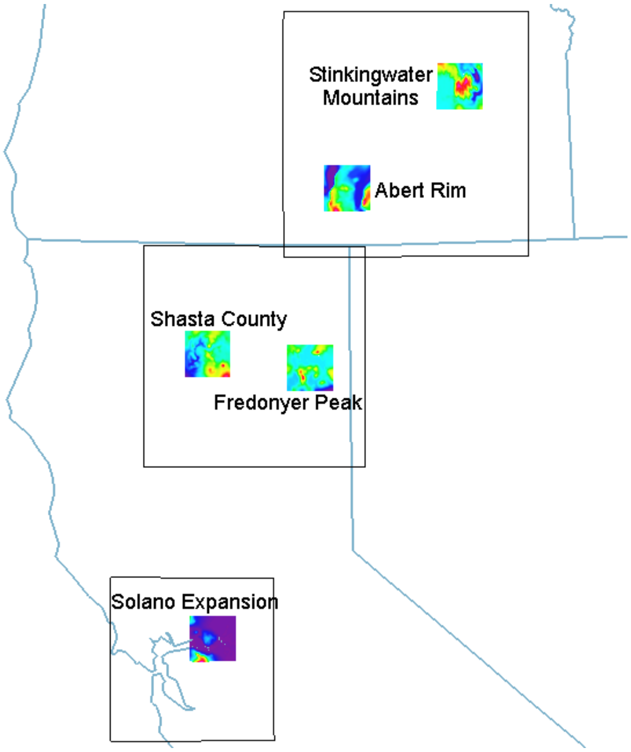
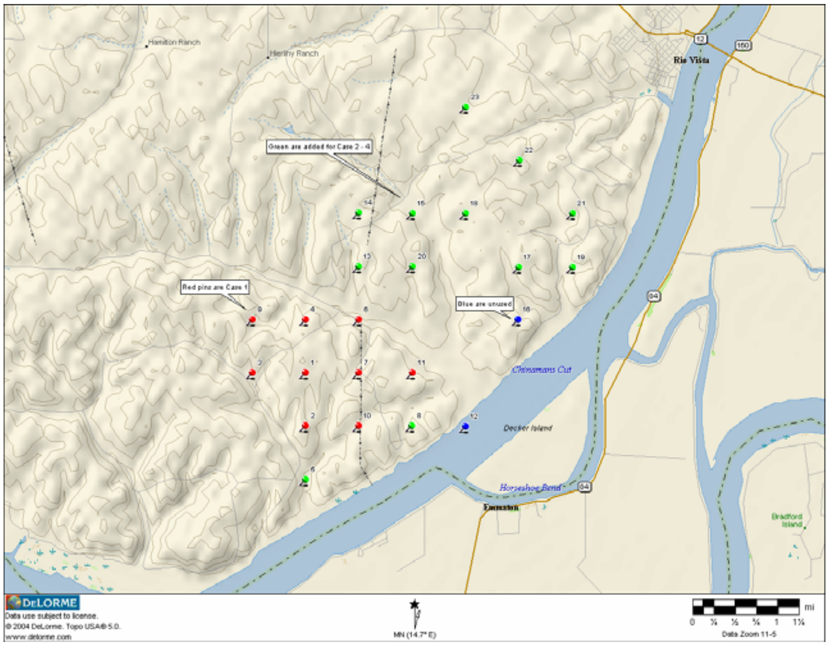

Stinkingwater Mountains
Abert Rim
Shasta County
Fredonyer Peak
Solano Expansion

Figure 2. General location of regions and sites for MM5 meteorological simulation

Source: EnerNex Corporation


Hamilton Ranch
Herlihy Ranch
Rio Vista
Green are added for Case 2 - 4
Red pins are Case 1
Blue are unused
Chainsmans Cut
Decker Island
Horseshoe Bend
Emmaton
Bradford Island
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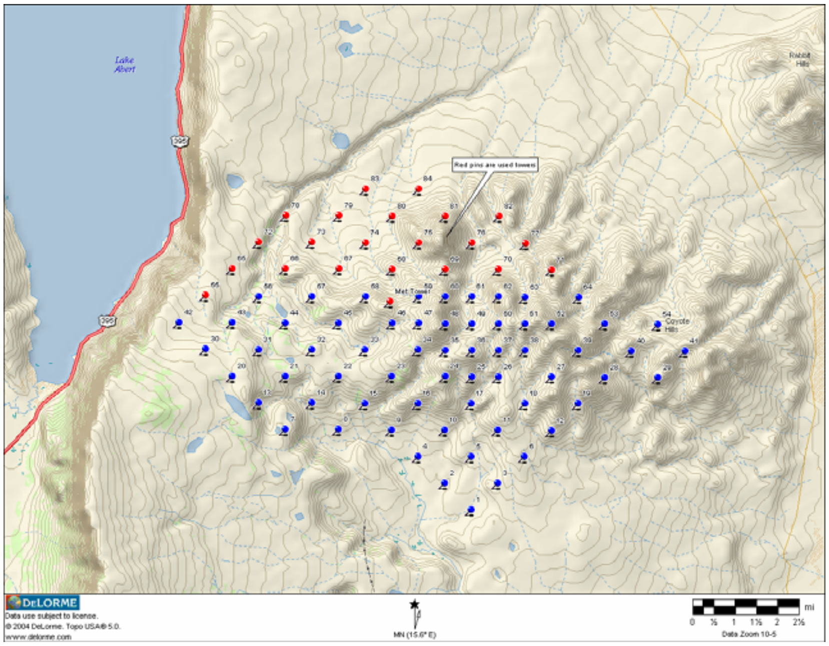
www.delorme.com
MN (14.7° E)
mi
Data Zoom 11-5

Figure 3. Location of proxy meteorological towers at Solano

Source: EnerNex Corporation


Lake Abert
395
Rabbit Hills
Red pins are used towers
Met Tower
Coyote Hills
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Data use subject to license.
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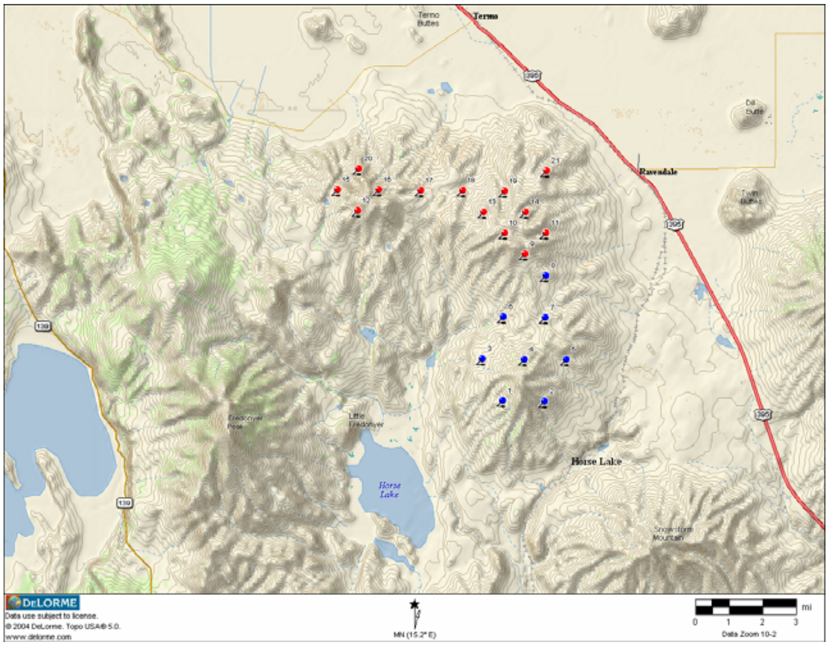
MN (15.6° E)
mi
Data Zoom 10-5

Figure 4. Location of proxy meteorological towers at Abert Rim

Source: EnerNex Corporation


Termo
Termo Buttes
395
Ravendale
Horse Lake
Horse Lake
Fredonyer Peak
Little Fredonyer
139
Snowstorm Mountain
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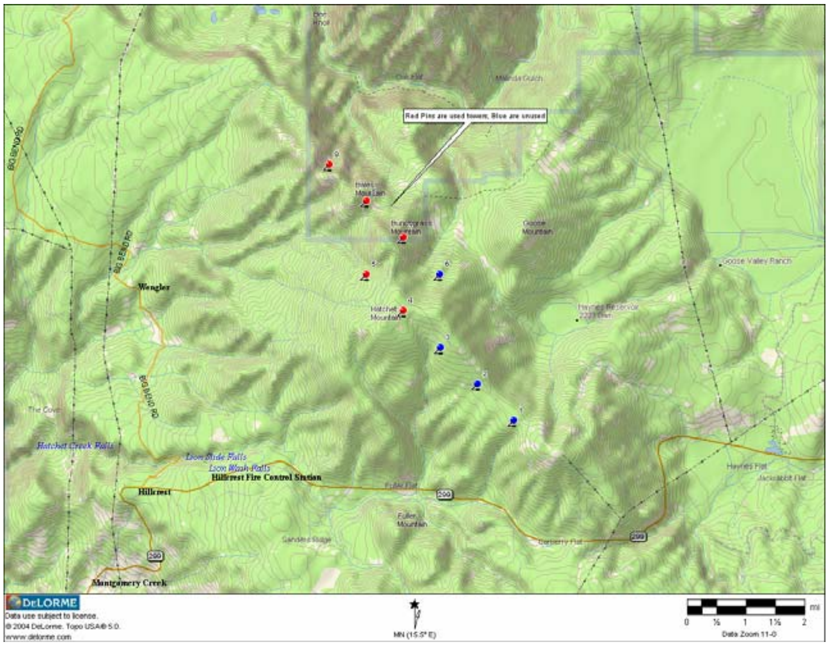
mi
0 1 2 3
Data Zoom 10-2

Figure 5. Location of proxy meteorological towers at Fredonyer Peak

Source: EnerNex Corporation


Red Pins are used towers, Blue are unused
BIG BEND RD
Wengler
Goose Mountain
Goose Valley Ranch
Hatchet Mountain
Hatchet Creek Falls
Lion Slide Falls
Hillcrest Fire Control Station
Hillcrest
299
Montgomery Creek
The Cove
Haynes Flat
DeLORME
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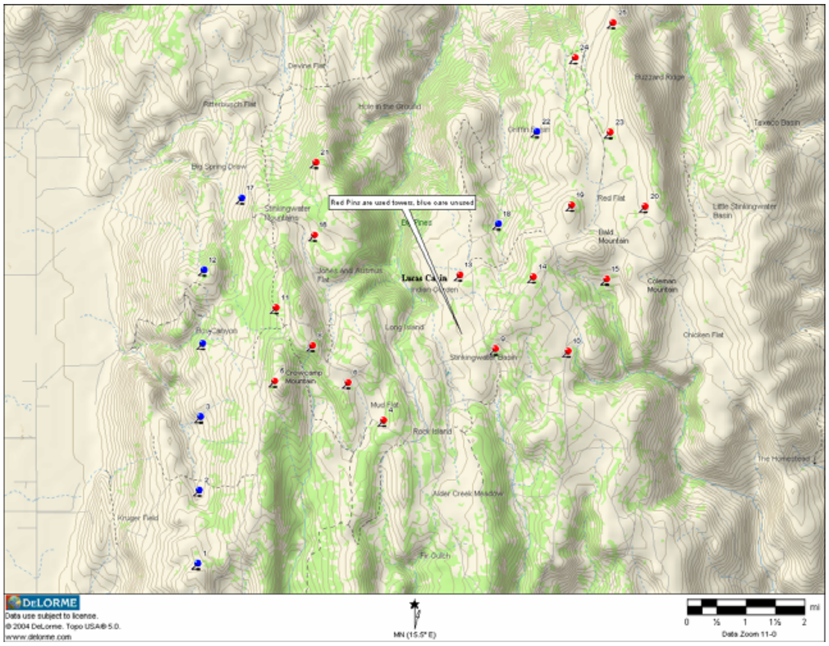
www.delorme.com
MN (15.5° E)
mi
0 ½ 1 1½ 2
Data Zoom 11-0

Figure 6. Location of proxy meteorological towers at Shasta

Source: EnerNex Corporation


Red Pins are used towers, blue ones unused

Devine Flat
Ritterbusch Flat
Hole in the Ground
Big Spring Draw
Stinkingwater Mountains
Jones and Aubrus Flat
Lucas Cabin
Indian Garden
Long Island
Rosy Canyon
Crowcamp Mountain
Mud Flat
Rock Island
Alder Creek Meadow
Fir Gulch
Kruger Field
Griffin Basin
Buzzard Ridge
Texaco Basin
Red Flat
Little Stinkingwater Basin
Bald Mountain
Coleman Mountain
Chicken Flat
Stinkingwater Basin
The Homestead
1
2
3
4
5
6
8
9
10
11
12
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16
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MN (15.5° E)
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mi
Data Zoom 11-0

Figure 7. Location of proxy meteorological towers at Stinkingwater

Source: EnerNex Corporation

2.1.2 Definition of Wind Generation and Study Scenarios

The second step in developing the wind generation model consists of defining specific deployments of wind generation in the areas for which the historical wind speeds are synthesized through simulation.

Table 1 contains a definition of seven specific study scenarios to be assessed in the later analytical tasks. These are based on four wind generation development scenarios:

- Expansion of the existing Solano facility to 102 MW.
- Further expansion of Solano to 250 MW.
- Addition of 200 MW at a geographically remote location (Abert Rim) for a total installed wind generation capacity of 450 MW.
- Further expansion at geographically remote sites (Stinkingwater Mountains, Shasta County, and Fredonyer Peak) for a total wind generation capacity of 850 MW.

Additional study scenarios are based on these wind generation scenarios in combination with different assumptions or additions to the SMUD system.

Table 1. Study cases and wind generation scenarios

	Solano	Abert Rim	Stinkingwater Mountains	Shasta County	Fredonyer Peak	Iowa Hill	Schedule	Rationale	PIRP Regimes
Case 1	102 MW (34)						Possible 2008	SMUD plan	PIRP & non-PIRP
Case 2	250 MW (84)						Possible 2010	SMUD tentative plan	Non-PIRP;
									Scale PIRP from Case 1
Case 3	250 MW (84)	200 MW (67)					Possible 2011	Diversity benefits;	Non-PIRP;
								Needed for 20%	Scale PIRP from Case 1?
Case 4	250 MW (84)	200 MW (67)	200 MW (67)	50 MW (17)	150 MW (50)		Possible 2013	Diversity benefit;s	Non-PIRP;
								Accelerated RPS	Scale PIRP from Case 1?
Case 5	250 MW (84)					400 MW	Possible 2014+	SMUD tentative plan	PIRP & non-PIRP
Case 6	250 MW (84)	200 MW (67)				400 MW	Possible 2014+	Diversity benefits;	Non-PIRP;
								Needed for 20%	Scale PIRP from Case 5?
Case 7	250 MW (84)	200 MW (67)	200 MW (67)	50 MW (17)	150 MW (50)	400 MW	Possible 2014+	Diversity benefits;	Non-PIRP;
								Accelerated RPS	Scale PIRP from Case 5?

Source: EnerNex Corporation

To create the wind generation models, chronological wind speed data from the MM5 simulations is transformed into various time series of wind power. This requires specification of the number of turbines to be assigned to each proxy tower and the type of turbine (power curve) to be considered. While the inner grid resolution is relatively high, areal representation of each proxy tower is large enough to contain more than a single commercial wind turbine.

Table 2 details the allocation of turbines to proxy towers for each wind generation scenario. A power curve corresponding to the performance of the Vestas V82 1.65 MW turbine (formerly NEG-Micon 1.65 MW) was selected as the base turbine, but the maximum power rating was scaled to 3.0 MW. With the assumption of no more than four turbines within the cell represented by an extraction point, the maximum generation per proxy tower is 12 MW.

Table 2. Assumed turbine population and capacity by case

Site	Solano	Abert Rim	Stinkingwater Mountains	Shasta County	Fredonyer Peak
Case 1					
MW	102				
Turbines	34				
Towers	9				
Case 2					

Site	Solano	Abert Rim	Stinkingwater Mountains	Shasta County	Fredonyer Peak
MW	250				
Turbines	84				
Towers	21				
Case 3					
MW	250	200			
Turbines	84	67			
Towers	21	17			
Case 4					
MW	250	200	200	50	150
Turbines	84	67	67	17	50
Towers	21	17	17	5	13

Source: EnerNex Corporation

2.1.3 Wind Forecast Synthesis

The wind forecast error series is based upon calculated error patterns that have been developed for other studies in other areas of the country. These error patterns, while not a perfect approach to estimating a forecast, allow the application of consistent calculated error data over a year and allow control of the mean absolute error (MAE). The error series are calculated from a simulation of actual wind generation and synthetic forecast calculations. The actual energy error is calculated on an hourly basis and then normalized by the nameplate capacity, giving a per-unit error series that can be applied to any simulated power series to estimate a forecast for that series.

For this study, a set of correlated error series where selected. These series were selected from an area of approximately the same geographic diversity as the study area for this study. Each site (Solano, Abert Rim, Stinkingwater Mountains, Shasta, and Fredonyer) was assigned an error series.

Each hourly power generation series was calculated and then the error series was applied to calculate the estimated forecast. The forecast is clipped to allow generation only in the range of zero to the nameplate of the plant. An adjustment factor is applied to the forecast to force a desired MAE for the forecast. In this study, the day-ahead forecast is fixed to an MAE of 17.5 percent and a second forecast used for 3 to 10 hours out is fixed to an MAE of 10 percent. Any calculation requiring a forecast of two hours out or less is based on persistence.

2.2 Task 2–SMUD System Models and Data

The project team constructed the model from data provided by SMUD detailing its hydro, thermal, purchased, and proposed wind energy resources. Load data is based on actual load data for the year 2004 and peak load forecast data for the primary study year 2011.

- A (modified) projected peak load of 3190 MW.
- Projected energy requirements of 12,361 gigawatt-hours (GWh).
- Updates to various existing power purchase and sale contracts.

2.2.1 Thermal Plant Models

The thermal plants modeled in this study were derived from data provided by SMUD. The facilities include all thermal plants on-line at the beginning of the study and the Consumnes 495 MW combined cycle gas plant commissioned in 2007. All thermal plants are natural gas turbines or combined cycle plants. All plants are assumed to be under the control of SMUD and are Automatic Gain Control (AGC) capable.

Thermal plant models were derived from the data provided by SMUD for the plants, as shown in Table 3.

Table 3. SMUD thermal plants

Unit Name	Plant Description	Rating
CONSUMNES	Consumnes Power Plant	495 MW Combine Cycle Gas
CVFA	Carson Ice Co-Gen	53 MW Combine Cycle Gas
CVFA_PEAKER	Carson Ice Peaker	40 MW Gas Turbine
MCCLELLAN	McClellan CT	65 MW Gas Turbine
SCA	Proctor & Gamble Co-Gen Plant	116 MW Combine Cycle Gas
SCA_PEAKER	Proctor & Gamble Peaker	42 MW Gas Turbine
SPA	Campbell's Soup Co-Gen Plant	161 MW Combined Cycle Gas

Source: Sacramento Municipal Utility District

In addition to the thermal plants, four contract purchases are modeled as thermal units, as displayed in Table 4.

Table 4. Dispatchable long term contract modeled as thermal units

Vendor	Thermal Unit Name	Max MW	Heat Rate (MmBtu/MWh)	Availability
PacificCorp Power Marketing	PPM1	50	8.005	24x365
PacificCorp Power Marketing	PPM2	100	10.2	06/01 to 09/31
City of Klamath Falls	CKF1	50	8.005	24x365

Vendor	Thermal Unit Name	Max MW	Heat Rate (MmBtu/MWh)	Availability
City of Klamath Falls	CKF2	30	10.2	04/01 to 10/31

Source: Sacramento Municipal Utility District

The following table shows the detailed capacity, costs, and reserve capability information used in the wind integration portion of the study.

Table 5. Thermal unit parameters

Unit Name	Fast Start	Unit Type	Econ Min	Econ Max	Cur Cap	Max RegUp Rsv	Max RegDn Rsv	Max Rsp Rsv	Max Opr Rsv	Min Up	Min Dn	Startup Ramp Rate	Shutdown Ramp Rate	Dispatch Ramp Rate	Maint Price Per Startup	Maint Incr Price
SPA	Y	GT	60	155	161	25	25	50	150	6	6	300	300	300	3000	3.00
CVFA	Y	GT	27	53	53	25	25	50	150	1	1	300	300	300	1500	3.00
CVFA_PEAKER	Y	GT	20	40	40	25	25	50	150	1	1	300	300	300	0	3.00
SCA	Y	GT	30	116	116	25	25	50	150	1	1	300	300	300	1500	3.00
SCA_PEAKER	Y	GT	20	42	42	25	25	50	150	1	1	300	300	300	0	3.00
MCCLELLAN	Y	GT	35	65	65	25	25	50	150	3	0	300	300	300	1500	3.00
CONSUMNES	Y	GT	128	495	495	25	25	50	150	4	4	300	300	300	0	3.00
UARP	Y	HYDR	10	626	690	50	50	50	150	1	1	100	300	300	0	0.00
PPM1	Y	GT	25	50	50	8	8	17	50	1	1	100	100	100	0	4.00
PPM2	Y	GT	50	100	100	8	8	17	50	1	1	100	100	100	0	4.00
CKF1	Y	GT	25	50	50	8	8	17	50	1	1	100	100	100	0	4.00
CKF2	Y	GT	15	30	30	8	8	17	50	1	1	100	100	100	0	4.00

Source: Sacramento Municipal Utility District/EnerNex Corporation

The fuel of all thermal plants is natural gas. The assumed price of gas is $7.06/MCF. Gas heat content is assumed at 1.026 MmBTU/MCF)

2.2.2 Hydro Facility Profiles

Hydro profiles for the Upper Atmosphere Research Program (UARP) and the Western Area Power Association (WAPA) were derived by determining an average monthly proportion of load served by the two facilities and scaling hourly load for the month by these proportions. This was meant to be a simple way to generate the annual series for these initial tests.

Table 6 provides monthly summary of the hourly loading for the two hydro facilities. Detailed hourly data for both hydro profiles is available in a separate spreadsheet.

UARP has been presented as a base point schedule (fixed amount of megawatt-hours (MWh) for each hour with a price of $0/ MWh. The original regulation capability numbers have been modified to reflect the ramp rates to give more realistic values. REGUP and REGDOWN and responsive reserve capabilities are calculated as max 10 ramp, or 50 MW. Operating reserve is calculated as max 30 minute ramp, or 150 MW.

WAPA has been presented as a firm contract transaction with energy price of $18.22/MWh.

Table 6. Monthly summary of the hourly loading for the two hydro facilities

	UARP				WAPA			
Month	Min (MW)	Average (MW)	Max (MW)	Energy (MWh)	Min (MW)	Average (MW)	Max (MW)	Energy (MWh)
Jan	101	151	197	112220	56	84	109	62345
Feb	72	103	136	69243	40	57	76	38468
Mar	82	121	156	89943	45	67	86	49968
Apr	162	243	468	174979	90	135	260	97210
May	196	294	486	218652	109	163	270	121473
Jun	181	316	622	227780	101	176	345	126545
Jul	149	276	520	205133	83	153	289	113963
Aug	153	282	532	209931	85	157	296	116628
Sep	146	259	507	186227	81	144	282	103460
Oct	79	120	184	88941	44	66	102	49412
Nov	87	126	176	90747	48	70	98	50415
Dec	101	152	201	112994	56	84	111	62775

Source: Sacramento Municipal Utility District/EnerNex Corporation

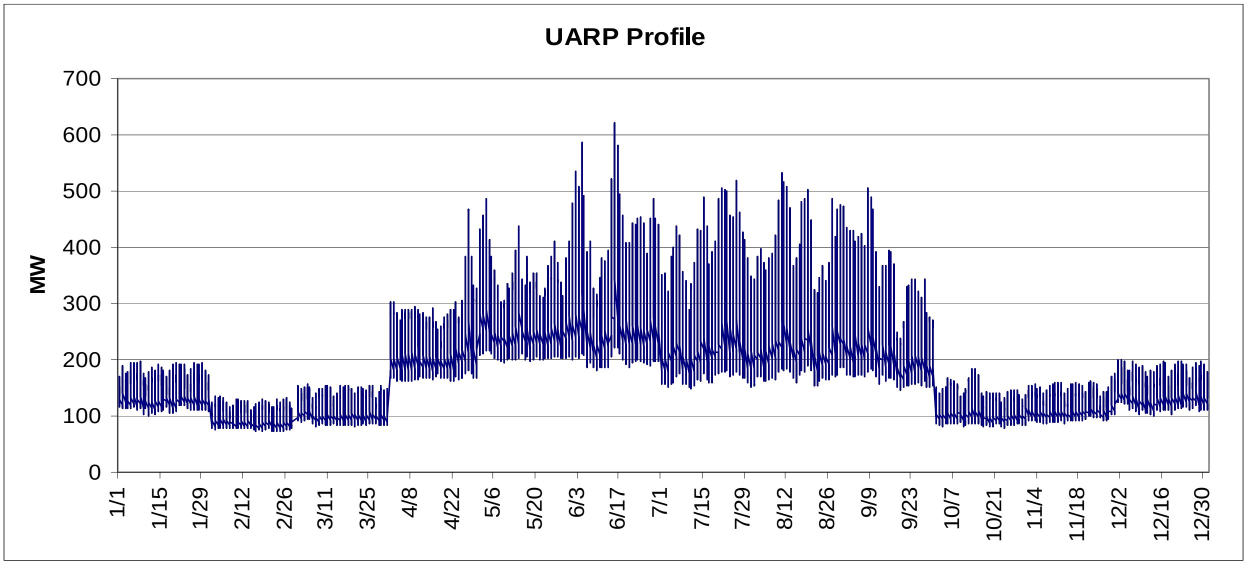


Figure 8. UARP generation profile

Source: Sacramento Municipal Utility District/EnerNex Corporation

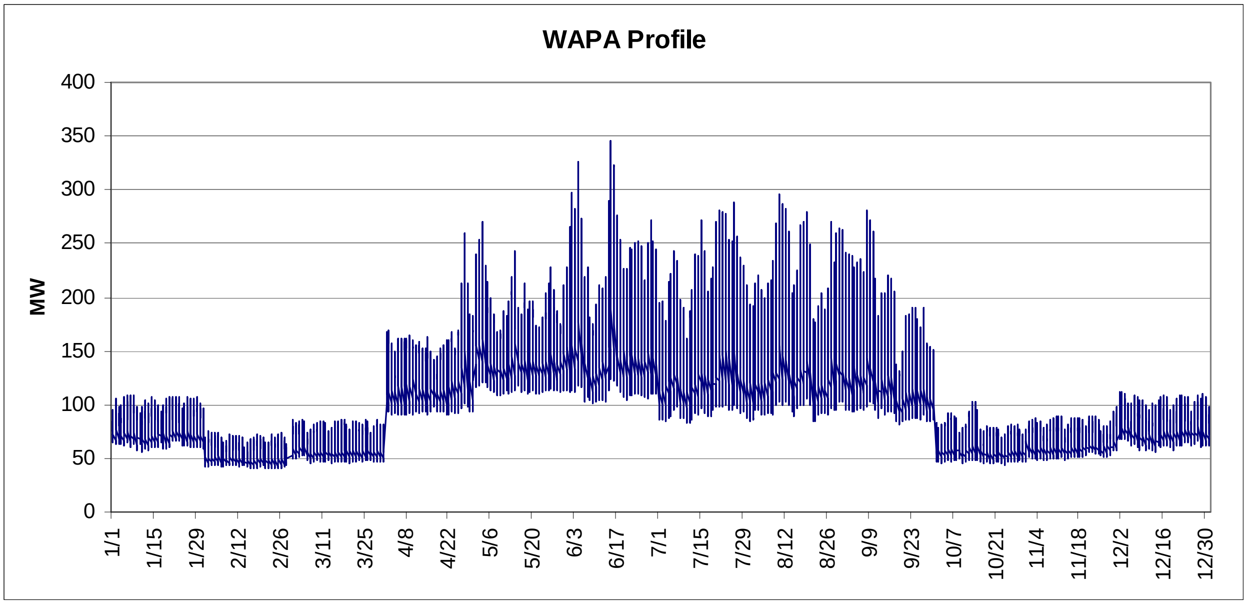


Figure 9. WAPA contract generation profile

Source: Sacramento Municipal Utility District/EnerNex Corporation

2.2.3 Pumped Storage Facilities Model

For several of the cases in the wind integration cost analysis, the authors evaluated effects of a pumped storage facility. SMUD provided the base data for that facility. The following parameters were used:

- Pump/Generator Capacity–400 MW
- Pond Capacity–6215 MW
- Min Allowable Pond–300 MW
- Round Trip Efficiency–81 percent

Day-Ahead Purchases

Day-ahead market prices are the NP15 hourly prices provided by SMUD for 2011. A maximum limit of 2000 MW was imposed on the day-ahead purchase imports.

The project team determined the hourly day-ahead purchases through performing unit commitment simulation. These values are fixed when performing the economic dispatch simulation (real time simulation).

2.2.4 Long Term Contract Modeling

Long term contracts given by SMUD were divided into fixed and dispatchable power. The terms of the contracts were deduced from the hourly delivery and price data for the month of September 2003. Some simplifications were made where details were difficult to determine.

Intermediate and short term contracts were not modeled at this stage. Also, no spot market purchases were allowed according to the specification of the study. The long term and day-ahead purchases account for 85 percent of the energy purchases from the September 2003 detailed data. The remaining 15 percent is from spot purchases and short- and medium-term contracts.

The dispatchable contracts were provided with equivalent heat rates for the costing of energy. These contracts have been modeled as thermal unit, simple cycle gas turbines for the purposes of the wind integration cost calculations.

The details of fixed power contracts are given in Table 7.

Table 7. Fixed long term contracts

Vendor	Contract Name	Max MW	Dispatch	Cost $/MWh	Availability
Pacific Power and Light	PPL	100	Fixed	15.32	24x365
PacificCorp Power Marketing	PPMC1	50	Fixed	NP15	24x365
PacificCorp Power Marketing	PPMwind	23	Fixed	18.22	24x365
Calpine Energy Services	Calpine	50	Fixed	NP15	24x365
Avista Group	Avista	75	Fixed	COB	24x365
East Bay Municipal	EBMUD1	10	Fixed	NP15	24x365
East Bay Municipal	EBMUD2	30 20	Fixed	NP15	05/01 to 06/14 All other days

Source: Sacramento Municipal Utility District/EnerNex Corporation

The simulation load values used in this study are obtained by scaling the 2003 load values provided by SMUD to the peak value of the estimated 2011 load forecast. The purpose of the scaling is to maintain the correlation between load values and calculated wind generation. The simulated load values for year 2011 are calculated as follows:

Actual 2011 load value at hour i: $L_i^{2011\_actaul} = (\frac{L_i^{2003}}{L_{peak}^{2003}}).L_{peak}^{2011\_SMUD\_given\_forcast} = (\frac{L_i^{2003}}{2802})*3190$

The total amount of consumed energy using SMUD 2011 load forecast is 12,361,436 MWh

The total amount of consumed energy using the rescaled 2011 load is 12,014,436 MWh

Energy error for scaled values of 2011 load= $\frac{12,014,436-12,361,436}{12,361,436} = -2.8\%$

Load forecast values for year 2011 are obtained from the calculated actual load values by applying an hourly time series of percentage error in load forecast.

$$L_i^{2011\_forecast} = L_i^{2011} * (1 + \frac{e_i}{100})$$

Where e_i is the percentage forecast error at hour i.

2.3 Task 3–Calculations for Effective Load Carrying Capability

High levels of power system reliably mandate that electric utilities have sufficient generating capacity to meet peak demand. Given the long lead-times for developing supply resources and the relative inflexibility of demand, planning for adequate generating capacity over time can be as far out as 20 years and is a critical activity for electric utilities and regional reliability organizations.

Because all supply resources are subject to unplanned outages or de-ration of maximum capacity, the required capacity for a given year in the planning horizon must be in excess of the forecast peak load by some margin. Capacity reserve margins of 15 percent are common in the industry, although there will periods where this margin is either higher or lower.

Power systems reliability assessments, both deterministic and probabilistic, are divided into two basic aspects: system adequacy and system security. System adequacy examines the availability of sufficient facilities within the system to satisfy the consumer load demand without violating system operational constraints. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to consumer load points. Adequacy is therefore associated with static conditions that do not include system disturbances. System security presents the system's ability to respond to sudden shocks or disturbances within the system, such as the loss of major generation and/or transmission facilities and short circuit faults. Under such conditions, security studies show system ability to survive without cascading failures or loss of stability.

Adequacy studies are a vital part in planning for adding new generation capacity to meet the growth in load. Adequacy of generation systems studies consider only how available generating units can meet system load without considering the transmission network constraints. Several probabilistic indices are used for the assessment of the adequacy of generation system, including Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE), Expected Energy Not Supplied (EENS), Loss of Load Frequency (LOLF), and Loss of Load Duration (LOLD).

Wind generation is primarily a source of electric energy since its output cannot be practically dispatched to a specified level at any given hour. Because of this apparent limitation, assigning a "capacity value" of zero to wind generation would seem appropriate. However, it can be demonstrated by any of the conventional analytical methods used to assess power system reliability that some non-zero percentage of a given amount of wind generation can be "counted on" to meet load. The magnitude of the contribution will be a function of several factors, including the nature of the wind resource, its correspondence with system load patterns, and the types and reliability of conventional supply resources comprising the system.

The objective of the analysis documented here is to determine the contribution to system adequacy of the four levels of wind generation identified for the SMUD wind integration study. The research team considered four wind generation levels–102 MW, 250 MW, 450 MW, and 850 MW. Hourly wind production data from historical years 2003 and 2004 was derived from meteorological simulations described in the Task 1 report for this project.

2.3.1 Proposed Wind Power Generation Scenarios for SMUD

The wind generation scenarios defined in Task 1 are detailed in Table below. It is important to recognize that the specific definition of the scenarios is critical to the resulting capacity contribution. The forces driving the wind resource may or may not be related to factors that drive electric demand, and this correlation has a significant impact on the resulting capacity value. Changing the amounts of generation at each site, or adding other wind generation locations to the scenario, would change the results of the computations.

Table 8. SMUD Wind generation scenarios

Site name	Solano	Abert Rim Site 1	Stinkingwater Mountains Site 2	Shasta County Site 3	Fredonyer Peak Site 4	Total
Case 1	102 MW (34)					102 MW
Case 2	252 MW (84)					252 MW
Case 3	252 MW (84)	201 MW (67)				453 MW
Case 4	252 MW (84)	201 MW (67)	201 MW (67)	51 MW (17)	150 MW (50)	855 MW

*Numbers in () indicate number of 3 MW turbines used for site model.

Source: EnerNex Corporation

2.3.2 SMUD Load Modeling

The load model used in the adequacy analysis is the forecast load for SMUD in years 2011 and 2013 based on the actual load in years 2003 and 2004, respectively. In this report, the generation adequacy analysis has been performed by considering the wind generated power as a load modifier. That is achieved by assuming the amount of average wind power produced at certain hour as a negative load as given in the following equation:

New value for load at hour i: $L_i^{new} = L_i^{old} - W_i^{average}$

Where L_i^{new} and L_i^{old} are the modified and actual loads at hour i respectively, $W_i^{average}$ is the average wind power production at hour i. This approximation is accurate when the capacity of the wind generating units is a small fraction of installed generation. Based on that, five different hourly load values have been obtained as follows:

- Base case: load at hour i = forecast load at hour i
- Case 1: load at hour i = forecast load at hour i – forecast wind generation at hour i for Case 1
- Case 2: load at hour i = forecast load at hour i – forecast wind generation at hour i for Case 2
- Case 3: load at hour i = forecast load at hour i – forecast wind generation at hour i for Case 3
- Case 4: load at hour i = forecast load at hour i – forecast wind generation at hour i for Case 4

Based on that, peak loads for each case are presented inTable 9

Table 9. Modified Peak load for each study scenario

Year	Peak Load	
	2011	2013
Base Case	3721 MW	3615 MW
Case 1	3697 MW	3613 MW
Case 2	3698 MW	3608 MW
Case 3	3698 MW	3612 MW
Case 4	3698 MW	3605 MW

Source: EnerNex Corporation

2.3.3 Capacity Value Estimation from Load and Wind Data

The integration of intermittent sources into a generating system raises questions about the capacity value of these sources. It is important to know the correlation between wind power generation variation and load variation. This can be quantified by calculating the capacity factor of the wind power plant during a specific period of time. The capacity factor can be defined as the amount of wind power that can replace conventional power generation without making the system less reliable. Based on historical wind generation data, the capacity factor for a wind power plant is calculated as follows:

Capacity factor over a certain period =

$$\frac{\text{Amount of generated wind energy in MWh (during this period)}}{\text{Wind plant nameplate (rated) power in MW*period duration in hours}}$$

Capacity factor for the different four wind generation cases for the SMUD system have been calculated for the highest 17, 170, 1700, and total load hours as given inTable 10. Arranging the 17,522 hourly load values in the two years from highest to lowest load values, capacity factor is calculated for the highest 0.05 percent, 0.1 percent, 1 percent, 25 percent, 50 percent, 75 percent, and 100 percent load values as shown in Figure 10.

Table 10. Calculated capacity factor for different load hours for years 2011 and 2013

Year	**Capacity Factor**											
	2011 No of highest load hours considered				**2013 No of highest load hours considered**				**Both 2011 and 2013 No of highest load hours considered**			
	17h	**170h**	**1700h**	**All**	**17h**	**170h**	**1700h**	**All**	**17h**	**170h**	**1700h**	**All**
Case 1	52.8%	35.65%	32.9%	33.3%	20.0%	30.3%	34.6%	37.3%	44.4%	33.2%	35.4%	35.3%
Case 2	50.4%	34.2%	31.8%	32.1	18.9%	28.9%	33.5%	36.0%	42.2%	31.5%	34.1%	34.0%
Case 3	29.7%	23.5%	28.0%	32.7%	12.5%	21.0%	28.2%	32.3%	24.7%	21.6%	26.7%	32.5%
Case 4	17.1%	17.1%	25.3%	32.2%	10.3%	16.7%	25.9%	31.1%	14.6%	16.1%	22.7%	31.7%

Source: EnerNex Corporation

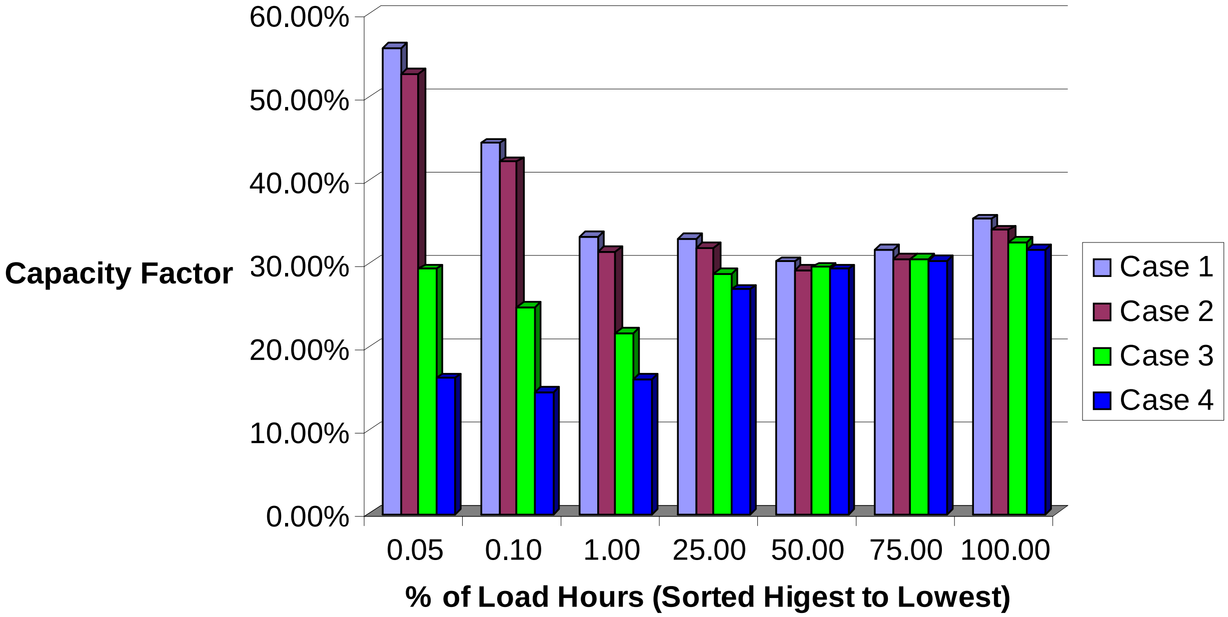


Figure 10. Capacity factor for years 2011 and 2013 (the two years, 17,522 hourly load values are ordered from highest to lowest)

Source: Sacramento Municipal Utility District/EnerNex Corporation

2.3.4 Calculation of Forced Outage Rate (FOR) of SMUD Generating Units

The adequacy analysis presented in this report is using the two-state model for generating units, i.e. every generating unit is assumed to have a two-state, up (full generating capacity) and down (zero generating capacity). The probability of any unit to be down is equal to its Forced Outage Rate (FOR). Each unit goes from the up state to the down state with a failure rate λ. Each unit goes from the down state to the up state with a repair rate μ.

The first step in generation adequacy analysis is to assess these parameters for the SMUD system generating units using historical generation availability data. In this report, failure and repair rates for SMUD generating units were calculated from the given historical operation data from 1995 to 2001 as follows:

- Calculate the total number of hours the generating unit was forced to be out of service during year i.
- Calculate the average down time for the unit at year i:

  t_{down} (year i) = Total forced down hours/number of times the unit is down
- Calculate the probability that unit is down at year i:

  P_{down} (year i) = forced outage hours/(in-service hours + forced outage hours)
- Calculate the unit average down time:

$t_{down} = \sum t_{down}$ (year i) / number of years the unit is in service

- Calculate the unit average repair rate

  $\mu = 1/t_{down}$

- Calculate the unit failure probability:

  FOR = $\sum P_{down}$ (year i) / number of years the unit is in service

- Calculate the unit failure rate λ using the calculated values of FOR and μ.

  FOR= $\lambda/(\lambda+\mu)$

SMUD Hydro Generating Units

The SMUD generation system has 11 hydro units with total capacity of 695 MW. For each Hydro unit FOR, λ and μ values have been calculated by using the unit availability data from 1995 to 2001 as explained in previous section. Results are displayed in Table 11.

Table 11. Calculated FOR, λ and μ values for SMUD Hydro units

Unit name	Capacity MW	FOR	repair time hrs	failure rate/hrs	repair rate/hrs
CAMINO #1	75	0.007202451	34.81	0.000208409	0.028727377
CAMINO #2	75	0.008838646	26.940	0.000331006	0.037118869
CAMP FAR WEST	7	0.009777083	30.095	0.000328079	0.033227848
JAYBIRD #1	72	0.017362741	32.376	0.000545753	0.030886668
JAYBIRD #2	72	0.017744523	77.918	0.000231847	0.012833989
JONES FORK	11.5	0.01287575	45.302	0.000287925	0.022073895
LOON LAKE	82	0.002345951	14.003	0.000167928	0.071413997
ROBB's PEAK	29	0.001163113	2.631	0.000442603	0.380090498
UNION VALLEY	46.7	0.001473331	7.334	0.000201186	0.136350355
WHITE ROCK #1	112	0.017615741	77.759	0.000230606	0.012860319
WHITE ROCK #1	112	0.001395736	13.509	0.000103461	0.074023159

Source: Sacramento Municipal Utility District/EnerNex Corporation

SMUD Co-Generating Units

The SMUD co-generation system has nine thermal units with a total capacity of 480 MW. For each Thermal unit FOR, λ and μ values have been calculated by using the unit availability data from 1995 to 2001 as explained in previous section. Results are demonstrated in Table 12.

Table 12. Calculated FOR, λ and μ values for SMUD co-generating thermal units

Unit name	Capacity MW	FOR	repair time hrs	failure rate/hrs	repair rate/hrs
SPA (CAMPBELL SOUP) COGENERATION	110	0.018761123	34.458	0.000554882	0.029021258
SPA (CAMPBELL SOUP) Peaker	50	0.028091039	49.421	0.000584834	0.020234416
CARSON ICE COMBINED CYCLE	57	0.003665558	5.917	0.00062176	0.169000483
CARSON ICE PEAKER	42	0.015776977	19.287	0.00083114	0.051849451
SCA (PROCTER & GAMBLE) gas turbine 1A	42	0.01000168	21.260	0.000475191	0.047035951
SCA (PROCTER & GAMBLE) gas turbine 1B	42	0.011774914	18.534	0.000642875	0.053954117
SCA (PROCTER & GAMBLE) steam	32	0.00140505	3.053	0.000460917	0.327582442
SCA (PROCTER & GAMBLE) gas turbine 1C Peaker	42	0.016139456	20.0	0.000820211	0.05
McClellan CT	60	0.072223852	132.876	0.000585849	0.007525726

Source: Sacramento Municipal Utility District/EnerNex Corporation

New Generating Units and Transmission Contracts

A new combined cycle unit (Consumnes Power Plant) has been added recently to SMUD generating resources. The unit rated power is 500 MW. The FOR for this unit has been assumed to be 0.02. That means the total amount of generation in the SMUD system is 695 MW (hydro), 480 MW (thermal), and 500 MW (new thermal unit), for a total of 1675 MW. This amount of power is less than the SMUD system peak load. The extra needed power to meet load demand is taken from the California ISO system through firm transmission contracts.

To perform generation adequacy analysis, these contracts have been modeled by four fictitious generating units with each having a capacity of 615 MW and a FOR of 0.02. These values have been selected to achieve an hourly LOLE of 2.4 hours/year (i.e. 24 hours/10 years) for the base case with the 1 pu peak load for year 2011. This means the system total generating capability is 4135 MW, compared to the peak load of 3721 MW, which represents 11.12 percent generating reserve.

Capacity Outage Table for SMUD Generating System

The recursive unit addition algorithm has been used to perform adequacy analysis for the SMUD generating system. The first step in this algorithm is to construct the generating system capacity outage table. This table determines the cumulative probability of X MW or more of generation to be out of service. The capacity outage table for the SMUD generating system rounded to the nearest 50 MW is provided in Table 13

Table 13. Generating capacity outage table for all SMUD resources

Capacity out X MW	Capacity in Y MW	Cumulative probability (X MW or more is out) (Y MW or less is in)
0	4135	1
50	4085	0.30192318
100	4035	0.15886928
150	3985	0.10751144
200	3935	0.09886669
250	3885	0.09734756
300	3835	0.09714564
350	3785	0.0971225
400	3735	0.09712017
450	3685	0.09711998
500	3635	0.09711996
550	3585	0.08270935
600	3535	0.07975624
650	3485	0.02105361
700	3435	0.00906273
750	3385	0.00479059
800	3335	0.0040726
850	3285	0.00394668
900	3235	0.00392996
950	3185	0.00392805
1000	3135	0.00392785
1050	3085	0.00392784
1100	3035	0.00392784
1150	2985	0.00273791
1200	2935	0.00249406
1250	2885	0.00062162
1300	2835	0.00024111
1350	2785	0.00010721
1400	2735	0.00008476
1450	2685	0.00008084
1500	2635	0.00008032
1550	2585	0.00008026
1600	2535	0.00008025
1650	2485	0.00008025
1700	2435	0.00008025
1750	2385	0.0000434
1800	2335	0.00003585
1850	2285	0.00000858
1900	2235	0.00000309
1950	2185	0.0000012
2000	2135	0.00000089
2050	2085	0.00000083
2100	2035	0.00000082
2150	1985	0.00000082
2200	1935	0.00000082
2250	1885	0.00000082
2300	1835	0.00000082
2350	1785	0.00000032
2400	1735	0.00000021
2450	1685	0.00000005
2500	1635	0.00000002
2550	1585	0.00000001
2600	1535	0
2650	1485	0
2700	1435	0
2750	1385	0
2800	1335	0
2850	1285	0

Source: EnerNex Corporation

2.3.5 Calculation of Equivalent Load Carrying Capacity

Capacity factor calculation is not sufficient to judge the benefits of adding wind generation to a certain system. It is also not appropriate for a wind plant with a 30 percent capacity factor to have a FOR of 70 percent because the amount of wind generation can be predicted ahead of time and the reduction in generating power is not a random, out-of-service process.

Adding intermittent resources to the system leads to an increase in the overall generation system adequacy. This increase in system reliability can be quantified by calculating the increase in system load levels until the previous reliability value is achieved before adding the intermittence resources; this fictitious load enlargement is called as Equivalent Load Carrying Capability (ELCC).

Procedure for Calculating ELCC

The general steps for calculating ELCC for a certain system to examine how new wind power plants will improve system generation reliability are as follows:

1. Based on historical wind data on the proposed wind power plant locations, wind speed can be forecast for a number of years in the future. Based on this forecast, the amount of wind generating power in MW can be predicted in an hourly time series.
2. Generation LOLE is calculated for the system base case without having any wind power added.
3. Generation LOLE is calculated while considering different scenarios of wind power generation and treating wind power generation as a negative load.
4. Steps 2 and 3 are repeated for the same load curve but with different peak values.
5. A chart describes the relation between LOLE and load peak value in pu of base case peak value is created for all cases.
6. The chart is used to calculate ELCC for certain wind generation scenario. First, move from the base case curve point : X_1= 1 pu, Y_1= LOLE value of 24 hours per 10 years to this scenario curve point: X_2, Y_2= LOLE value of 24 hours per 10 years, the difference $X_2 – X_1$ represents the possible increase in system peak load. Consequently, ELCC is calculated:

$$\text{ELCC \%} = \frac{\text{The possible increase in system peak load without reducing system LOLE}}{\text{Total wind plant nameplat (rated) power}}$$

Calculation of Generation System Reliability Using the Recursive Unit Addition Algorithm

A brief explanation of the algorithm used to calculate LOLE of the SMUD generating system is given in this section. In this report, every generating unit is assumed to have a two-state up (full generating capacity) and down (zero generating capacity). The probability of any unit to be down is equal to its FOR. Each unit goes from the up state to the down state with a failure rate λ. Each unit goes from the down state to the up state with a repair rate μ. Assuming the system under study is having n generating units, the total number of states for all possible combinations of generating units installed is 2^n.

The first step in the unit addition algorithm is to construct the generating system capacity outage table. Assuming a system with n generating units, the capacity outage probability table is constructed in ascending order for Unit 1. Unit 2 is then added and the capacity outage table is updated. This process is repeated until the last unit is added and the final capacity outage table is obtained.

The second step in the algorithm is to use the capacity outage table to calculate *LOLP* for each of the 8760 hourly load values. Consider the load value at hour "i" is LH_i. Loss of Load Probability for this load value is $LOLP(LH_j)$. Finally, LOLP for the corresponding year is calculated as follows:

$$LOLP = \sum_{j=1}^{8760} \frac{LOLP(LH_j)}{8760}$$

Hourly LOLE in hrs per year is calculated:

$$LOLE = LOLP*8760$$

2.4 Task 4–Analysis of Intra-Hour Wind Generation Impacts

Most wind integration studies to date have employed an analytical methodology based on chronological simulation of power system operation at the hourly level. This hourly granularity is very common in conventional production costing analysis, and allows for long-term (i.e. annual or longer) simulation of the power system.

Because of the temporal resolution, the real-time control of generation for support of system frequency and balancing of the control area cannot be represented explicitly. Instead, the amount of capacity type required to perform this function is deployed indirectly to meet various reserve constraints that are placed on the unit commitment optimization and economic dispatch of units in the simulation.

While this has worked quite well for conventional production costing studies, there is some concern that it may be inadequate in some instances for wind generation studies. This is primarily due to the fact that increased reserve requirements and cost is of primary interesting in wind integration, whereas the reserve questions are generally much less important for other studies based on production costing simulations.

The objective of this task was to employ detailed, high resolution simulations of the SMUD control area to ascertain the impacts of wind generation on real-time operation of SMUD resources. The platform utilized for these simulations is the eterra-simulator from Areva T&D. The simulator is a component of Areva's Energy Management System (EMS) product line for utility control centers. Its primary purpose is to provide a realistic environment for training of system operators, which is why the product has also been known as the DTS (Dispatcher Training Simulator). The DTS utilizes all the core algorithms and processes used to manage a control area, but operates on a simulation model rather than from Supervisory Control and Data Acquisition (SCADA) signals as inputs and generation control pulses as outputs.

Areva's DTS has been modified to allow wind generation to be represented as a point-by-point generation value, so that the type of wind data generated for this study can be used directly to define wind generation. The DTS was also modified to allow the simulation to proceed as fast as possible, thereby making simulations of many days in a few hours time possible, depending on such factors as processor speed, model size, etc.

Initial work with the DTS platform focused on validating the simulation results against actual high-resolution historical data. In general, it was possible through much effort, trial and error, and a measure of innovation to produce results via simulation that correlated reasonably well to measurement performance. Figure 11 shows simulated results versus actual results over a week of operation. It should be noted that while the total generation from the simulation tracks the actual pretty well, there are some significant differences in the peak values of the measured Area Control Error (ACE), despite the fact that the overall trend matches well.

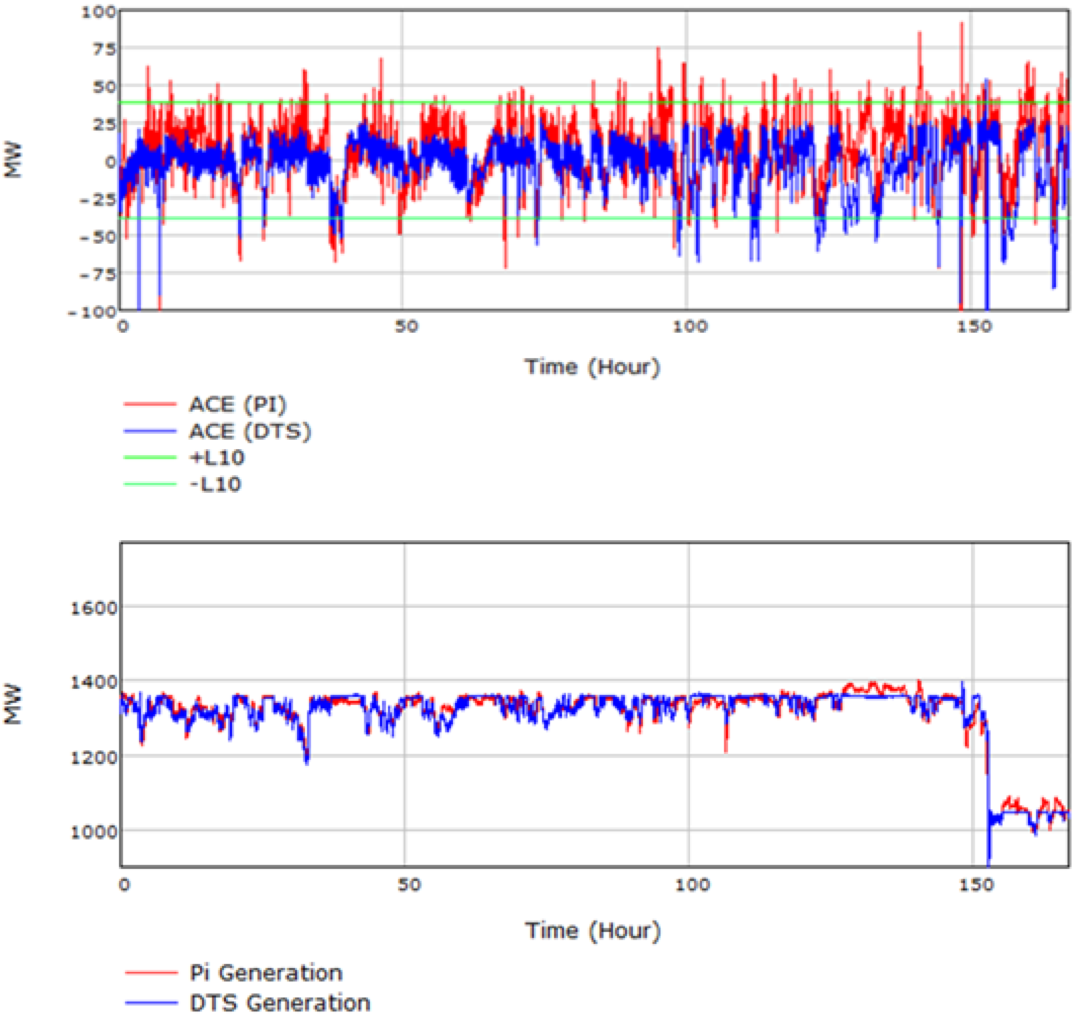
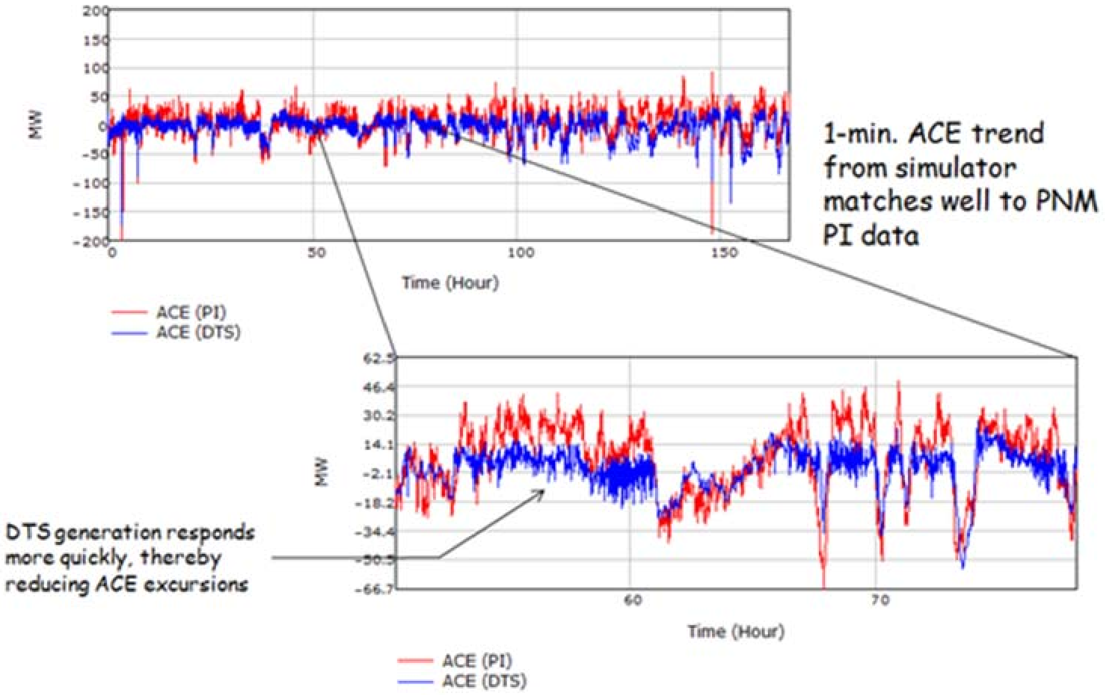


Figure 11. Comparison of simulation (blue) vs. actual (red) quantities from high resolution simulation.

Source: EnerNex Corporation

ACE is a critical metric in power system operation and control, since it is one of the two variables (interconnection frequency being the other) upon which all generation adjustments for purposes of manage the system are predicated. Figure 12 provides an expanded view of the ACE variable from simulation and from historical measurement. It is apparent from the figure that the generation in the simulator responds more quickly to control signals than in reality. Because of this, peak magnitudes of ACE–from which the critical performance metric for system control are drawn–are generally smaller in the simulation than actually experience in system operations.



1-min. ACE trend from simulator matches well to PNM PI data

DTS generation responds more quickly, thereby reducing ACE excursions

Figure 12. Comparison of ACE from historical archives and from simulation

Source: EnerNex Corporation

After significant discussion, the authors concluded that achieving a better correspondence between simulator ACE and reality would require that:

- Filters and algorithms through which raw ACE computations at intervals of a few seconds are processed must be adjusted to better match those in the actual EMS.
- The response of generators on automatic generation control (AGC) must be made non-ideal, either through manipulation of response rates or the addition of noise to the control pulses from the EMS.

As constituted, the project team was not able to provide the requisite expertise in either of these areas. Consequently, a new approach was required to assess and estimate the intra-hourly impacts attributable to the wind generation in the scenarios considered in this project.

This procedure is described in the next section.

Determining Reserve Requirements for Managing Incremental Variability

The common methodology for assessing the cost of integrating wind energy into a utility control area is based on chronological simulations of scheduling and real-time operations. Production costing and other optimization tools are generally used to conduct these simulations. In most cases, the "time-step" for these simulations is in one-hour increments. Consequently, many details of real-time operation cannot be simulated explicitly. Generation capacity that is used by operators to manage the system in real-time–i.e. the units on AGC utilized by the EMS for both fast response to ACE and that which is frequently economically re-dispatched to follow changes in control area demand–is assigned to one or more reserve categories available in the various programs.

At this level of granularity, the total reserve requirements for the system are a constraint on the optimization and dispatch. Supply resources in the model are designated by their ability to contribute to the system requirements in one or more reserve categories. In the course of the optimization or dispatch, the solution algorithm must honor the system reserve needs, and therefore is not able to use some capacity to meet load or fulfill transactions.

As a result, increasing a reserve requirement does not in and of itself increase operating cost. There are many hours when enough units with the appropriate capability are spinning and loaded such that the reserve requirements are met. However, there may be hours where the system reserve requirement dictates another unit start or keep efficient units below their maximums. Here costs will accrue, as the marginal cost to serve the load would increase.

In this context, there are two primary types of reserves. The first is comprised of the excess capacity that must be carried at all times for reliability. These are generally known as "contingency reserves", and as the name implies, can only be utilized when an event that meets of the definition of a contingency actually occurs.

The second category of reserves is used to balance the supply with the control area demand on a continuous basis. This includes minute-by-minute (or faster) adjustments to generation to compensate for load variations and frequency economic dispatch of units with movement capability to follow slower variations in control area demand.

For a given hourly load in the data set for the study, there are periods during that hour where the demand is higher and lower than the average. Generation must be adjusted to meet these values within the hour. Figure 13 illustrates this with actual data.

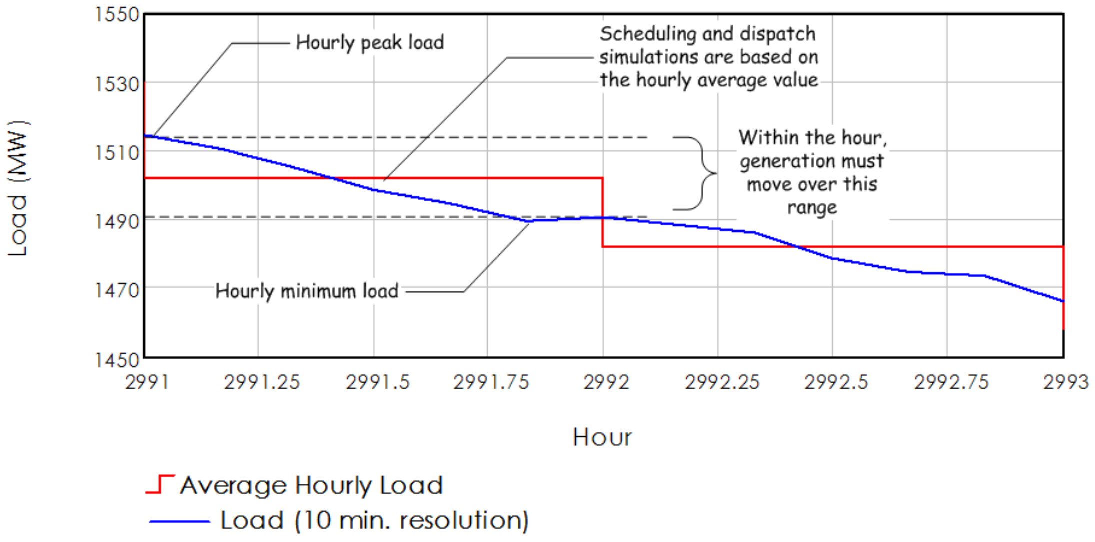


Figure 13. Hourly average and 10-minute load

Source: EnerNex Corporation

The purpose of this section is to describe a procedure for estimating the additional flexibility within the hour that would be required to manage a control area with significant wind generation. The analysis and experimentation are based on an annual record of load and wind generation at 10-minute intervals. The goal is to develop a "rule" for the amount of required flexibility using information available in the control room. The extended data records also provide a way to "test" the proposed rules.

The procedure for determining the required flexibility for load alone is as follows:

1. Using the 10-minute data, compute the hourly average value for load.
2. Compute the difference between each 10 minute value of load and the hourly average. The difference is the load following requirement.
3. Because of defined WECC ramp that takes place from 10 minutes before until 10 minutes after the hour, the "average" load value at the top of each hour is actually the average of the previous and next hour values (Figure 14). This adjustment will reduce the magnitude of the hourly load-following "envelope", since the greatest departure of 10-minute values usually occur at the start and end of each hour using this method.
4. Devise an algorithm that operators could use to project the maneuverability needed to follow load movements. For load alone, this algorithm is based on the previous hour average value (which is known) and the forecast average value for the next hour (which the authors assume can be perfectly forecast for load alone).
5. The estimated load following capability is then the difference between the next hour forecast average and the previous hour average.

6. The requirements are roughly symmetrical about the average value. In the morning, for example, the load at the beginning of the hour will be less than the hourly average. If the unit basepoints are moved to the hourly average, there will be a need to back some generation down, and then move it up over the hour as the load increases. This rough symmetry also makes the math easier, but of course may not apply to how the IPC operators do things.
7. This load following "rule" is tested with the 10-minute data. The number of 10-minute load values outside of the up and down load following bands is computed. For the rule above, the number of "violations" is about 1800 out of almost 50,000 10-minute samples. It was also necessary to add in the REGUP/REGDN capacity since the 10 minute values are snapshots, not averages over the interval.

Figure 15 shows the results of the mathematical procedure described above in Points 1 and 2.

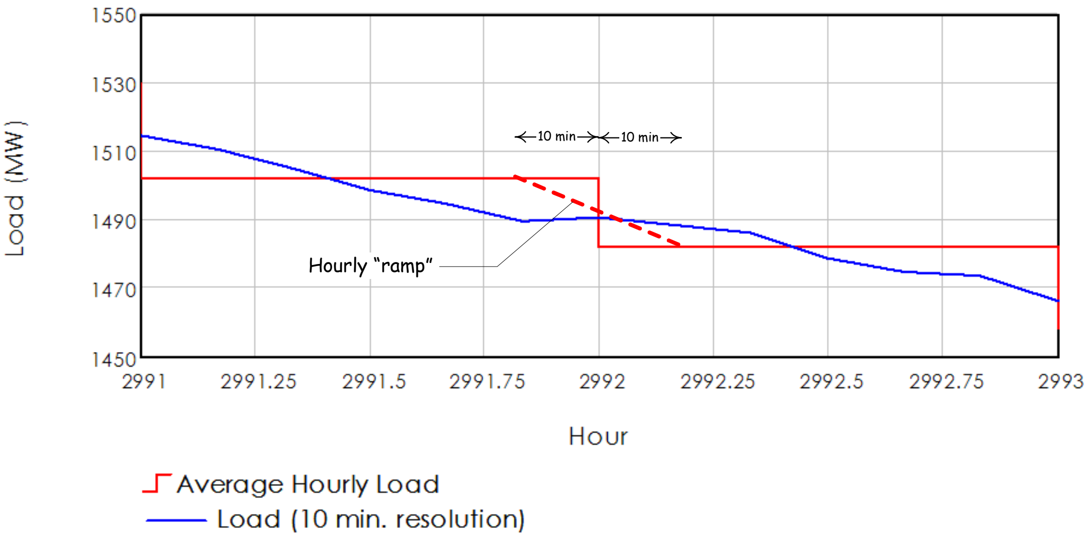


Figure 14. Hourly average load with WECC ramp between hours

Source: EnerNex Corporation

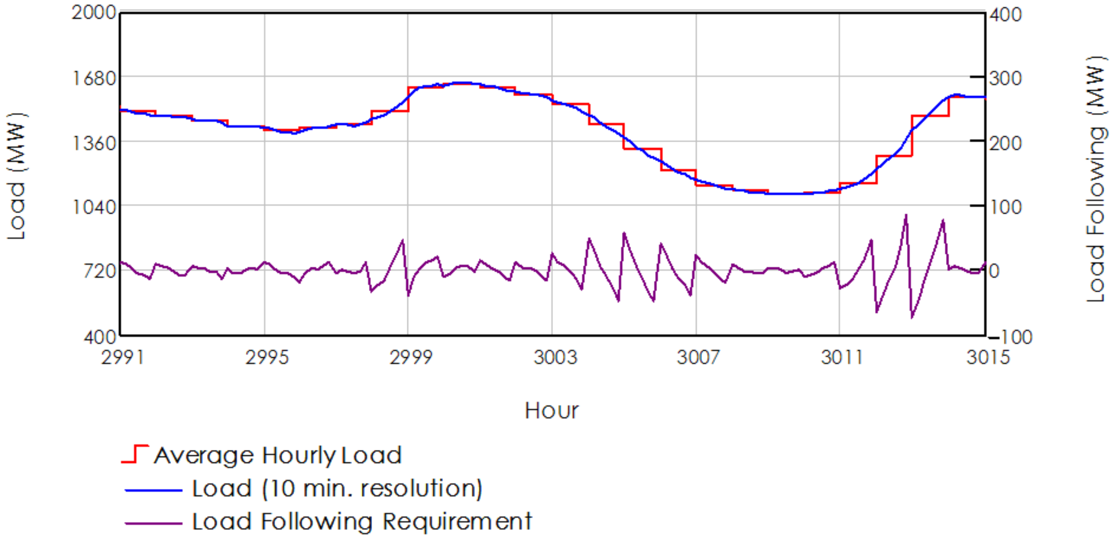


Figure 15. Hourly load, 10-minute load, and load following "requirement"

Source: EnerNex Corporation

In this initial analysis of load following requirements, it is assumed that base-point scheduled generation is committed to meet the hourly average load plus hourly transactions. All deviations from the hourly schedule, then, fall into the load-following bin.

One should consider the combination of regulation and load following functions, as is the case with SMUD, and the type of data utilized for the analysis described here. The 10-minute data used in this analysis was calculated as the average of two 5-minute samples, so it is therefore nearer to the 10-minute average load than a single snapshot would be. This is important since the 10-minute ACE used for CPS2 compliance determination is calculated as a 10-minute average.

If the data is actually a sample taken every 10 minutes, it will be less indicative of the 10-minute ACE that is a primary driver for the EMS, as it would be more susceptible to containing artifacts of faster fluctuations that drive interconnection frequency support and are measured by the annual CPS1 metric.

The objective is to define an algorithm to compute the flexible generation required each hour to compensate adequately for the actual load from the hourly schedule. The algorithm must be based on information available to operators at the time that these short-term plans for operating reserves are being made. In a teleconference with SMUD, engineers described SMUD's "rule of thumb" for required system regulation capacity. Essentially, SMUD carries about 2/3 of the expected hour load change on AGC, giving rise to a substantial REGUP requirement in the morning and REGDOWN requirement in the evening. To manage the control area, however, there is need for REGDOWN in the morning and REGUP in the evening.

The analytical approach here is obviously simplified, so a direct mapping of SMUD's regulation reserve practice is somewhat difficult. Assessing deviations from the hourly average value has an advantage in that the flexibility requirement is symmetrical, rather than dependent on the load trend. This is also useful at higher penetrations of wind generation, where the direction of the control area demand may be less predictable than with load alone.

Impacts of Short-Term Forecast Error on Real-Time Operations

The previous analysis assumes that the reserves for the hour are planned on the basis of perfect knowledge of the next hour average load and wind generation. This is the situation with minimum uncertainty, and it relates mostly to the real-time operation of the system to compensate for inside-the-hour variations from some constant average value. In reality, there are operational decisions made some hours prior to this hour that will affect the generation flexibility that is needed to manage the control area.

If reserves must be allocated an hour or more before the operating hour, the known wind generation at that time may be substantially different than in the hour in question. This could impact the projected variability, as it is a function of the current production level. However, since the variability curves (Figure 39 and Figure 40) do not change dramatically with small changes in production level, the error here would be slight.

Larger impacts stem from decisions made based on short-term forecast information. If the window for hourly transactions closes one hour prior to the hour, it is necessary to cover deviations (i.e. forecast error) in the average hourly load net wind from the forecast hourly average load net wind (Figure 16). These deviations are covered by internal generation capacity that has been set aside for the hour in question. The capacity must be moveable in either direction, since the sign of the forecast error is not known. The deviation is constant through the hour in question and is actually an offset in the operating position (Figure 17). To cover the deviation, a resource must be scheduled at an operating point for the hour different than what was planned when setting up the hourly schedules. This action is not really following the load, but rather addressing an energy deficit or surplus from the schedule. If there are not options for transacting this error with the market or other control errors, generation capacity must be reserved to make this adjustment.

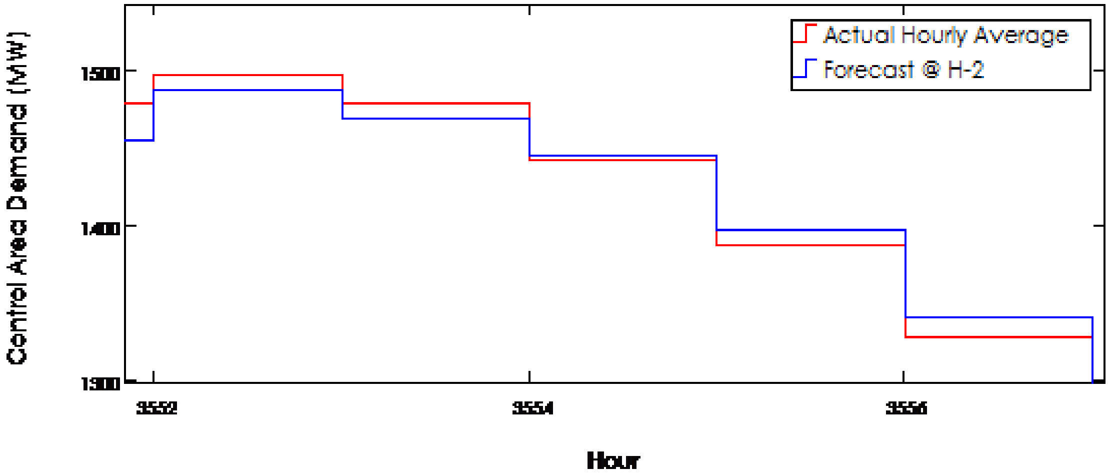


Figure 16. Actual and forecast hourly average values. Short-term forecast is made 1.5 hours prior to the start of the subject hour.

Source: EnerNex Corporation

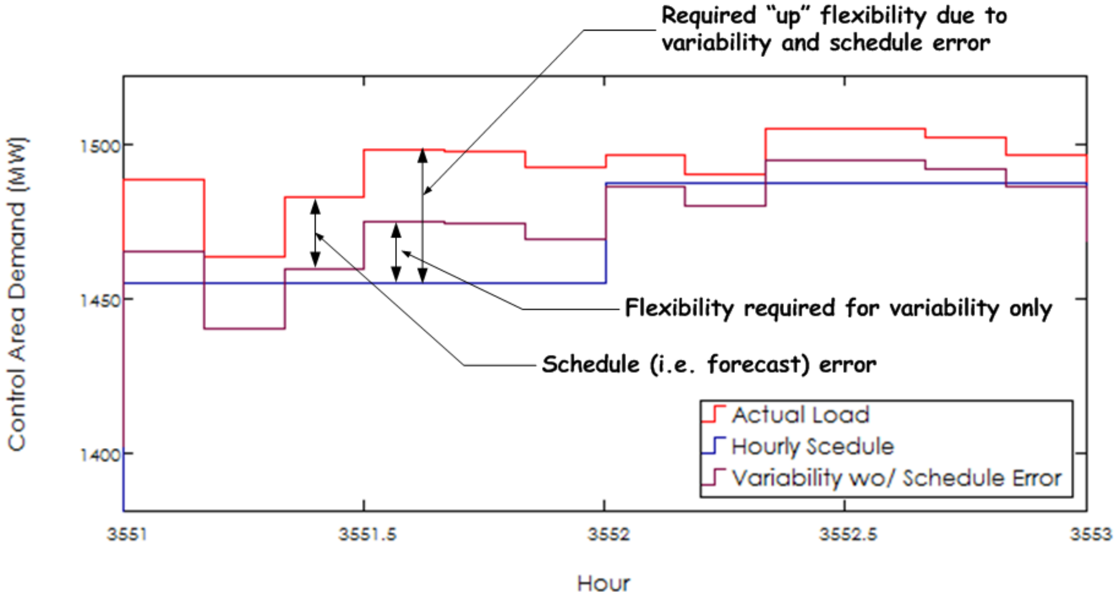


Figure 17. Additional intra-hour flexibility requirements due to schedule error bias

Source: EnerNex Corporation

Schedule deviations are a consequence of the net of short-term load and wind generation forecast errors. Some control areas augment their hourly reserves to ensure that enough controllable capacity is allocated to cover the shortfall or be turned down if there is surplus. The schedule deviation will be larger with wind generation. An approach similar to that used to calculate incremental regulation and load-following reserves can be employed to determine how much additional capacity must be allocated to cover incremental forecast error. For this example, it is assumed that in-the-day hourly transactions must be completed two hours before the subject operating hour. The error in a persistence forecast for wind generation during a two-hour horizon is calculated from the hourly wind generation data and summarized in Figure 42. Note that the standard deviations here are larger than for the one-hour persistence forecast (which would correspond to Figure 39 and Figure 40), illustrating the relatively rapid degradation of the persistence assumption over longer time frames.

2.4.1 Compensating for Fast Fluctuations in Load and Load net of Wind Generation

Input

- Load data from selected days of October 2003, January 2004, April 2004, and August 2004.
- Data was extracted from archives at sub-minute resolution.
- The sampling intervals are not constant through the data set, and range from a few to around 30 seconds.

Background

In the process of gathering operating practices, SMUD engineers described SMUD's "rule of thumb" for required system regulation capacity. Essentially, SMUD carries about 2/3 of the expected hour load change on AGC, giving rise to a substantial REGUP requirement in the morning and REGDOWN requirement in the evening. To manage the control area, however, there is need for REGDOWN in the morning and REGUP in the evening.

The objective of the load data analysis is to quantify these last two requirements.

Analysis

To assess the regulation capacity needed to compensate for fast up and down fluctuations in control area demand, an adaptive least-squares smoothing function was applied to the high-resolution load data to define a load trend characteristic. Figure 18 illustrates the trend characteristics and the actual load for a 16-hour period.

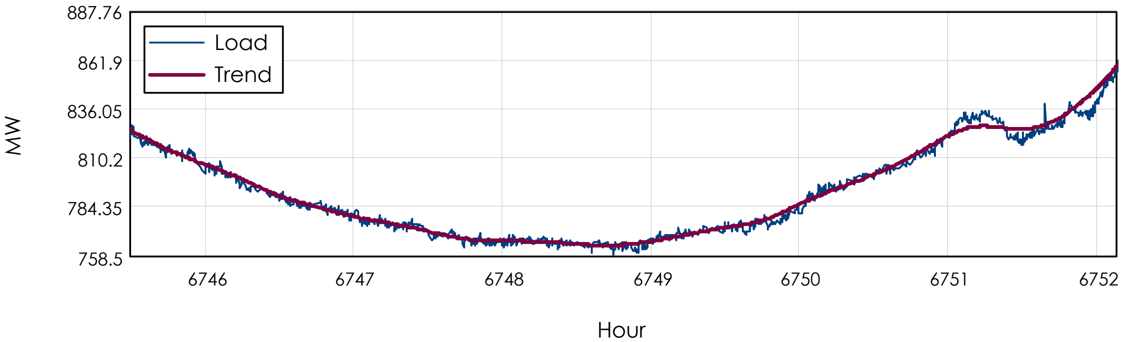


Figure 18. Trend of high resolution load data

Source: EnerNex Corporation

By subtracting the trend value from the actual load, the deviation for that period is obtained. The time plot of the deviations for the trend and load from Figure 18 is shown in Figure 19.

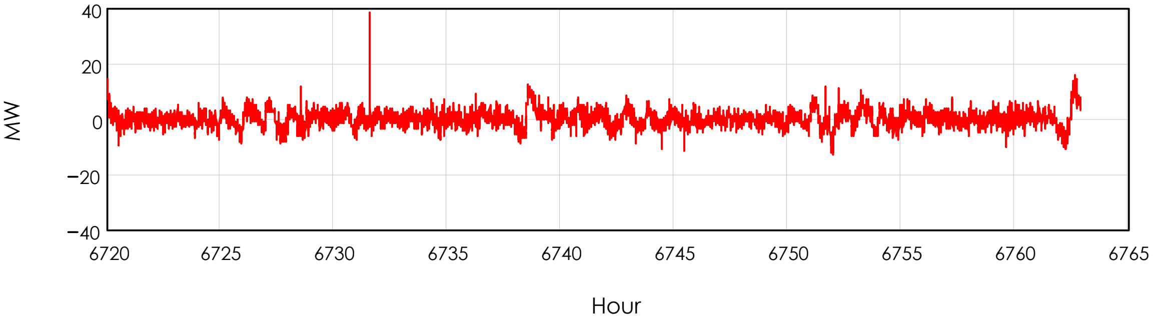


Figure 19. Short term load deviations from trend

Source: EnerNex Corporation

The detailed view of deviations for one of the daily periods in Figure 20 reveals a distribution that is roughly normal with a mean of about zero (which results from the intentional selection of the trending period).

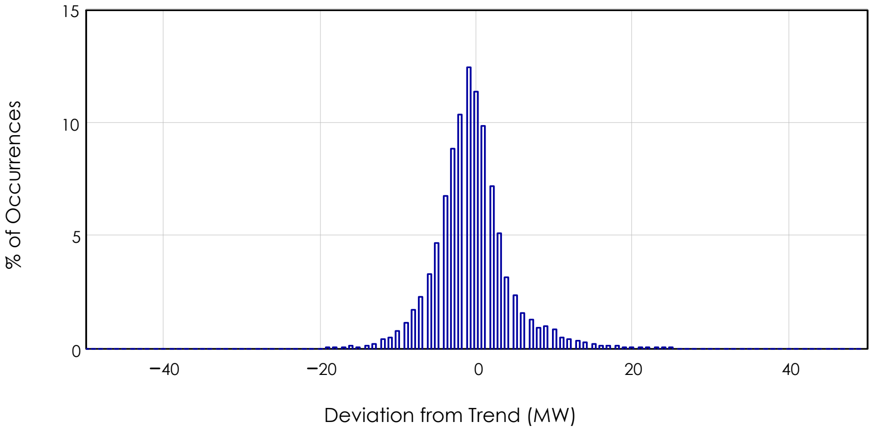


Figure 20. Distribution of short term load deviations

Source: EnerNex Corporation

Therefore, to compensate for almost all of these deviations, fast-responding regulation capacity equal to some multiple of the standard deviations would be necessary. Integration studies with other control areas have found this factor to range up to five. Applying this factor to the standard deviation of the load variations from the trend yields:

$$5\,\mathrm{stdev}\,(\mathrm{Dev}) = 15.7$$

$$\frac{5 \cdot \mathrm{stdev}\,(\mathrm{Dev})}{\max\,(L1)} = 1.13\ \%$$

The amount of fast-responding generation capacity on AGC required to compensate for the fluctuations in control area demand can be estimated from the statistical distribution of these variations over a period.

The average of five times the standard deviation of the SMUD load regulation characteristic for the 14 days analyzed is approximately 18 MW. The average as a percentage of peak load is 1.15 percent.

The conclusion from this analysis, therefore, is that the minimum REGUP and REGDOWN capacity for the SMUD control area is up to 18 MW. REGUP in the morning will be higher to account for 2/3 of the expected load pick up over the hour, with REGDOWN set to 18 MW. In the evening as load ramps down, REGDOWN will again be 2/3 of the expected hourly decrease, with REGUP at 18 MW.

The next step in this analysis will be to determine how this minimum regulating capacity requirement would be affected by wind generation.

Wind Plant Production Fluctuations on the Fast Regulation Time Scale

High resolution measurements obtained by the National Renewable Energy Laboratory (NREL) from operating wind plants of various sizes show that the standard deviation of the regulation characteristic can range from a few percent (<5 percent) for plants smaller than 50 MW to around 1 percent for plants 100 MW and larger.

These variations are almost certainly uncorrelated with the regulation variations of the load, since the former is driven by details of terrain and meteorology and the latter by individual customer choices and processes. The consequence of this statistical independence is that the variations of the load and wind combined can be estimated with simple algebra.

For SMUD, four levels of wind generation are being considered: 100 MW, 250 MW, 450 MW, and 800 MW. Applying the findings from the NREL measurement program and subsequent analysis, the standard deviation of the regulation characteristic for each of the scenarios would be 1 MW, 1.6 MW, 2.12 MW, and 2.91 MW, respectively. If the regulation characteristics of the individual subsets are truly uncorrelated, the regulation characteristic of the combination can be calculated from the statistics of the individual characteristics as follows:

$$\sigma_T = \sqrt{\sum \sigma_i^{\,2}}$$

where

σ_i = standard deviation of regulation characteristic of subset of load or wind

σ_T = standard deviation of regulation characteristics of aggregate control area demand

2.5 Task 5–Hourly Dispatch Simulations

2.5.1 Introduction

The hourly cases were completed for at least one full year of data for four wind generation penetration levels. Wind generation data for the all cases was synthesized from the WindLogics MM5 meteorological simulation data for the historical year 2003 as per the detailed scenario definitions presented and discussed previously. In review, the original proposed case list and scenarios are listed inTable 14.

Table 14. Full table of cases

	Solano	Site #1	Site #2	Site #3	Site #4	Total	Iowa Hill	Schedule	Rationale	PIRP Regimes
Case 1	102 MW					102 Mw		Possible 2008	SMUD plan	PIRP & non-PIRP
Case 2	250 MW					250 MW		Possible 2010	SMUD tentative plan	PIRP & non-PIRP
Case 3	250 MW	200 MW				450 MW		Possible 2011	Diversity benefits; Needed for 20%	PIRP & non-PIRP
Case 4	250 MW	200 MW	200 MW	50 MW	150 MW	850 MW		Possible 2013	Diversity benefit; Accelerated RPS	PIRP & non-PIRP
Case 5	250 MW					250 MW	400 MW	Possible 2014+	SMUD tentative plan	PIRP & non-PIRP
Case 6	250 MW	200 MW				450 MW	400 MW	Possible 2014+	Diversity benefits; Needed for 20%	PIRP & non-PIRP
Case 7	250 MW	200 MW	200 MW	50 MW	150 MW	850 MW	400 MW	Possible 2014+	Diversity benefit; Accelerated RPS	PIRP & non-PIRP

Source: EnerNex Corporation

This list leads to a total of four case sets of three or four scenarios each. Those sets are Base set of Cases 1 through 4 for PIRP and Non-PIRP and Cases 2 through 4 with Iowa Hill with both PIRP and non-PIRP. In addition, another sensitivity case was added to test the effect of discounting the forecast in the day-ahead commitments to hedge against wind coming in below the forecast value. This approach includes discounting the forecast by 50 percent in off peak months and assuming no wind for the forecast in peak months.

As these cases were run and assumptions changed throughout the study concerning reserves, real-time purchases, and sales, among others factors, the cases that were actually run are a subset of the table above. Actual cases run are described in the section "Case List and Model and Method Variations Among Case Sets."

2.5.2 Methodology

Wind generation integration cost is a function of the variability and uncertainty of energy delivery to the SMUD control area. Because wind generation can vary in an unfavorable pattern with respect to the system load, and can be predicted with only a certain degree of accuracy for forward periods in which optimum operating plans are constructed, additional cost can be incurred to serve the load not served by wind generation. The method used to calculate costs at the hourly level uses a series of comparative cases, and is designed to compare wind generation to a resource that does not possess attributes that contribute to integration cost.

The analysis mimics the activities of SMUD generation schedulers and real time operators. An optimal plan is constructed based on hour-by-hour forecasts of the control area demand for the next day. Using this plan as a starting point, the day is simulated using actual rather than forecast control area demand.

In the reference case, wind generation is represented as an energy source that imposes no additional burden in terms of scheduling and real-time operations. This is taken to be an ideal energy source that is perfectly predictable and operates so as not to increase control area ramping or regulation requirements. In the reference case, therefore, wind generation is represented as a flat block of energy for each day. The total energy for the day is exactly equal to what will be termed in the "actual" wind generation in later cases. This actual wind generation comes from the MM5 simulation data for the historical year.

With wind generation on the system, SMUD operators will use some type of next-day forecast of wind generation and load to construct the best plan for meeting the control area demand. When the day arrives, both hourly load and wind generation will likely depart from the forecasts used to develop the optimal plan. The consequence is that actual operations over the day will likely be less than optimal (i.e. lowest cost) for the actual load and actual wind generation.

Integration cost in this study is defined as the difference between the actual production cost incurred to serve the net of actual load and actual wind generation and the production cost from the reference case, where wind is perfectly known and adds no variability to the control area, and where next-day load is the only uncertainty.

The method for determining the costs at the hourly level proceeds as follows:

1. Run the unit commitment program (AREVA e-terra Commit) in Unit Commitment mode to develop a plan for serving the forecast load. Wind generation for the day is known perfectly, and is delivered in equal amounts each hour through the day. The results are saved as basis for the next step.
2. Run a second unit commitment simulating a morning-of re-commit with the day-ahead transactions fixed from Step 1 and allow the thermal units to recommit if necessary. This run uses fixed block wind energy and assumes perfect load knowledge. The results are saved as a basis for the next step.
3. If Iowa Hill is included in the case, a third unit commitment run is made to simulate hour-ahead commitment decisions on its operation. This run assumes perfect knowledge of load. The day-ahead transactions and unit commitment schedule from Step 2 are fixed but dispatch is allowed to vary based on the commitment.
4. Using the unit commitment from Steps 2 or 3 above, re-run the day with forecast load replaced by actual load. The program runs an economic dispatch based on the commitments and allows re-dispatched, available units to meet the actual load. Manually commit generation to meet load that cannot be served from the early same-day commitment. From these results, total production cost for the period is calculated and defined it as the "reference production cost."
5. Repeat Step 1 with the load forecast and the day-ahead wind energy forecast calculated from the actual wind pattern. Again, the results are saved with the day-ahead energy transactions.
6. Run a second unit commitment simulating a morning-of re-commit with the day-ahead transactions fixed from Step 5, and allow the thermal units to re-commit if necessary. This run assumes perfect load knowledge. Wind forecast uses the same error pattern as Step 5 but reduces the MAE of the forecast to 10 percent which is consistent with typical 2 to 10 hour out forecasts. The results are saved as a basis for the next step.
7. If Iowa Hill is included in the case, a third unit commitment run is made to simulate hour-ahead commitment decisions on its operation. This run assumes perfect knowledge of load and uses a two-hour persistence forecast for wind. The day-ahead transactions and unit commitment schedule from Step 6 are fixed but dispatch is allowed to vary based on the commitment.
8. Finally, using the unit commitment from Steps 6 or 7 above, re-run the day with forecast load replaced by actual load. The program runs an economic dispatch based on the commitments and allows re-dispatch available units to meet the actual load. Any unserved load left at the end of the dispatch is met using a generic thermal resource at 10.45 heat rate and the prevailing gas cost. From these results, total production cost for the period is calculated and defined it as the "actual production cost."

9. Integration cost is then calculated as the difference between the "actual production cost" and "reference production cost" normalized to the total annual wind energy for the case and is expressed in \$/MWh of wind energy.

Certain aspects of the methodology enumerated above merit additional emphasis:

- Load MWh and Wind MWh in "reference" and "actual" cases is identical. If wind generation is assumed to be a "must take" resource, the payment from SMUD to the wind generators is identical in both the "reference" and "actual" cases. Therefore, the cost per MWh of wind energy is not relevant to the analysis (i.e. it "subtracts out").
- Reference cases are run with base reserve requirements not modified by the wind. Actual cases are run with reserve requirement that are modified by the wind values as documented elsewhere in this report. The exception to this rule is PIRP case where the base reserve requirements are used also for the "actual" cases. This in effect says that in PIRP cases SMUD bears no burden for extra reserve requirements due to the wind.
- Consumnes combined-cycle plant was set as must run in all cases. Without this condition, there were a large number of overnight hours that did not meet energy and reserve requirements since no units under AGC were committed based on economics.

Finally, there is the issue of the wind generation attributes defined for the "reference" case. In this method, wind energy delivery is allowed to vary day-by-day, but the delivery within in a day is assumed to have the characteristics of a baseload resource. The argument for such treatment is that baseload resources impose no incremental burden on daily operations (save for decisions to de-commit large baseload resources). They neither assist with nor detract from the ramping or regulation requirements imposed by the load. In some respects, they are nearly invisible to the system operators.

The reference resource for wind assumed here is equivalent to an "as-available" energy contract with a third-party, where the terms of the contract allow the constant delivery to be scheduled a day in advance.

In some circumstances, defining the reference resource to be some type of conventional unit may be appropriate. Care must be taken, however, to operate this unit per the terms of the contract and within the capabilities of the actual proxy unit. As an example, if the reference resource were defined to be a simple cycle-gas turbine, it would not be appropriate to allow that unit to be dispatched to provide load following or other ancillary services unless the terms of the power purchase agreement were to explicitly include consideration of and compensation for this capability.

2.5.3 Case List and Model and Method Variations Among Case Sets

As with all complex studies, the methodology evolved as the study progressed and this study has experienced that effect. The ultimate effect is that some conditions that would be best left fixed across the cases are not constant between cases. Making all cases consistent would have required re-running of cases at the end of the study to match conditions. This would have been the best outcome but schedule restrictions precluded this final reconciliation. As a result, it is difficult to compare some of the case sets to each other.

The most significant difference between cases involves the calculation of reserves. The project team ran earlier case sets–Base, Iowa Hill Base, and Iowa Hill with Hasp–with reserve values based on wind levels for both reference and actual runs. This skews the results of these cases compared to the Reduced Forecast and Base PIR. Also, the Iowa Hill JIT uses one-hour persistence forecasts to determine final commitment of Iowa Hill. There are also other less important and subtle differences between the models.

The following table details the conditions for final case sets.

Table 15. Case set data descriptions

Base Case

	Run ID	Run Type	Load	Wind	Reserves	HASP Sales	Comment
Reference Case	1	Unit Commit	Forecast	Block	Base	No	Day-Head Commit
Reference Case	8	Unit Commit	Actual	Block	Wind Modified	No	Day-of Commit with Transaction Locked down
Reference Case	2	Economic Dispatch	Actual	Block	Wind Modified	No	
"Actuals" Case	3	Unit Commit	Forecast	Forecast (17.5% MAE)	Base	No	Day-Head Commit
"Actuals" Case	5	Unit Commit	Actual	Forecast (10% MAE)	Wind Modified	No	Day-of Commit with Transaction Locked down
"Actuals" Case	4	Economic Dispatch	Actual	Actual	Wind Modified	Yes - Calc 1	HASP is 2Hr Persits - Full Day-Ahead Forecast

Base PIR Case

	Run ID	Run Type	Load	Wind	Reserves	HASP Sales	Comment
Reference Case	1	Unit Commit	Forecast	Block	Base	No	Day-Head Commit
Reference Case	8	Unit Commit	Actual	Block	Base	No	Day-of Commit with Transaction Locked down
Reference Case	2	Economic Dispatch	Actual	Block	Base	No	
"Actuals" Case	3	Unit Commit	Forecast	Modifed Forecast (17.5% MAE)	Wind Modified	No	Day-Head Commit
"Actuals" Case	5	Unit Commit	Actual	Modified Forecast (10% MAE)	Wind Modified	No	Day-of Commit with Transaction Locked down
"Actuals" Case	4	Economic Dispatch	Actual	Actual	Wind Modified	Yes - Calc 2	HASP is 2Hr Persits - Day-Ahead Reduced Forecast

Reduced Forcast Base Case

	Run ID	Run Type	Load	Wind	Reserves	HASP Sales	Comment
Reference Case	1	Unit Commit	Forecast	Block	Base	No	Day-Head Commit
Reference Case	8	Unit Commit	Actual	Block	Base	No	Day-of Commit with Transaction Locked down
Reference Case	2	Economic Dispatch	Actual	Block	Base	No	
"Actuals" Case	3	Unit Commit	Forecast	Modifed Forecast (17.5% MAE)	Wind Modified	No	Day-Head Commit
"Actuals" Case	5	Unit Commit	Actual	Modified Forecast (10% MAE)	Wind Modified	No	Day-of Commit with Transaction Locked down
"Actuals" Case	4	Economic Dispatch	Actual	Actual	Wind Modified	Yes - Calc 2	HASP is 2Hr Persits - Day-Ahead Reduced Forecast

Iowa Hill Base

	Run ID	Run Type	Load	Wind	Reserves	HASP Sales	Comment
Reference Case	1	Unit Commit	Forecast	Block	Base	No	Day-Head Commit
Reference Case	7	Unit Commit	Actual	Block	Wind Modified	No	Day-of Commit for Iowa Hill Only
Reference Case	2	Economic Dispatch	Actual	Block	Wind Modified	No	
"Actuals" Case	3	Unit Commit	Forecast	Forecast (17.5% MAE)	Base	No	Day-Head Commit
"Actuals" Case	5	Unit Commit	Actual	Forecast (10% MAE)	Wind Modified	No	Day-of Commit with Transaction Locked down
"Actuals" Case	6	Unit Commit	Actual	2 Hour Persist	Wind Modified	Yes	2 Hour-Ahead Commit For Iowa Hill Only
"Actuals" Case	4	Economic Dispatch	Actual	Actual	Wind Modified	Yes - Calc 1	HASP is 2Hr Persits - Full Day-Ahead Forecast

Iowa Hill JIT Iowa Hill commitments

	Run ID	Run Type	Load	Wind	Reserves	HASP Sales	Comment
Reference Case	1	Unit Commit	Forecast	Block	Base	No	Day-Head Commit
Reference Case	7	Unit Commit	Actual	Block	Wind Modified	No	Day-of Commit for Iowa Hill Only
Reference Case	2	Economic Dispatch	Actual	Block	Wind Modified	No	
"Actuals" Case	3	Unit Commit	Forecast	Forecast (17.5% MAE)	Base	No	Day-Head Commit
"Actuals" Case	5	Unit Commit	Actual	Forecast (10% MAE)	Wind Modified	No	Day-of Commit with Transaction Locked down
"Actuals" Case	6	Unit Commit	Actual	1 Hour Persist	Wind Modified	Yes	1 Hour-Ahead Commit For Iowa Hill Only
"Actuals" Case	4	Economic Dispatch	Actual	Actual	Wind Modified	Yes - Calc 1	HASP is 2Hr Persits - Full Day-Ahead Forecast

Source: EnerNex Corporation

As noted, the Iowa Hill Cases and the base case were run with slightly different reserve conditions than the other cases. A time constraint at the end of this study prevented re-running these cases with the appropriate conditions. Comparison of these cases with the cases without pumped storage is somewhat difficult as a result.

The Iowa Hill "JIT commit" or "just in time commitment" case differs from the Iowa Hill base case in that the final commitment of the Iowa Hill facility is done using a one-hour persistence forecast instead of a two-hour persistence forecast. This implies that the commitment would be done at the top of the hour for that hour instead of an hour in advance.

The HASP sales are calculated as the two-hour persistence forecast minus the day-ahead wind forecast for a given hour. In the case of the discounted forecast cases, the discounted value is used for the HASP calculation. This is referred to a HASP calc 2 in the previous tables. If the full day-ahead is used, this is referred to as HASP calc 1.

Because of time constraints, PIRP and reduced forecast runs were not performed. These case sets maybe added at a later time to provide a more complete picture.

Chapter 3:
Project Outcomes

3.1 Task 1–Developing the SMUD Wind Generation Model

3.1.1 Simulation Results–Wind Model Characterization

The volume of data extracted from the MM5 meteorological simulations and converted to wind power time series is very large, and precludes direct publishing of the results. The following charts and tables provide an overview and quantitative characterization of the model data organized by the development scenarios described earlier.

Table 16. Calculated Capacity Factor by Site

	Solano		Abert Rim		Fredonyer Peak		Shasta County		Stinkingwater Mtns.	
	MW Nameplate	CF	MW Nameplate	CF	MW Nameplate	CF	MW Nameplate	CF	MW Nameplate	CF
Case 1	102	35%								
Case 2	252	34%								
Case 3	252	34%	201	30%						
Case 4	252	34%	201	30%	150	30%	50	42%	201	28%

Source: EnerNex Corporation

Table 17. Seasonal Capacity Factor by Site

	Solano Case 1	Solano Case 2	Abert Rim	Shasta County	Fredonyer Peak	Stinkingwater Mountains
Winter	21%	21%	48%	51%	38%	39%
Spring	36%	35%	34%	45%	35%	31%
Summer	52%	51%	15%	25%	22%	17%
Fall	29%	28%	26%	46%	27%	25%
Average	35%	34%	30%	42%	30%	28%

Source: EnerNex Corporation

Table 18. Aggregated Capacity Factor by Season for each of Four Study Cases

	Case 1	Case 2	Case 3	Case 4
Winter	21%	21%	33%	36%
Spring	36%	35%	35%	35%
Summer	52%	51%	35%	28%
Fall	29%	28%	27%	28%
Average	35%	34%	32%	31%

Source: EnerNex Corporation

Wind and load data for the four wind generation scenarios are shown in Figure 21 through Figure 24. Load patterns in these figures and the wind generation are for historical year 2003.

Average daily profiles for each wind generation case are depicted in Figure 25 through Figure 28. These profiles were created by averaging wind generation by hour over a monthly period. Seasonal profiles by case are shown in Figure 29.

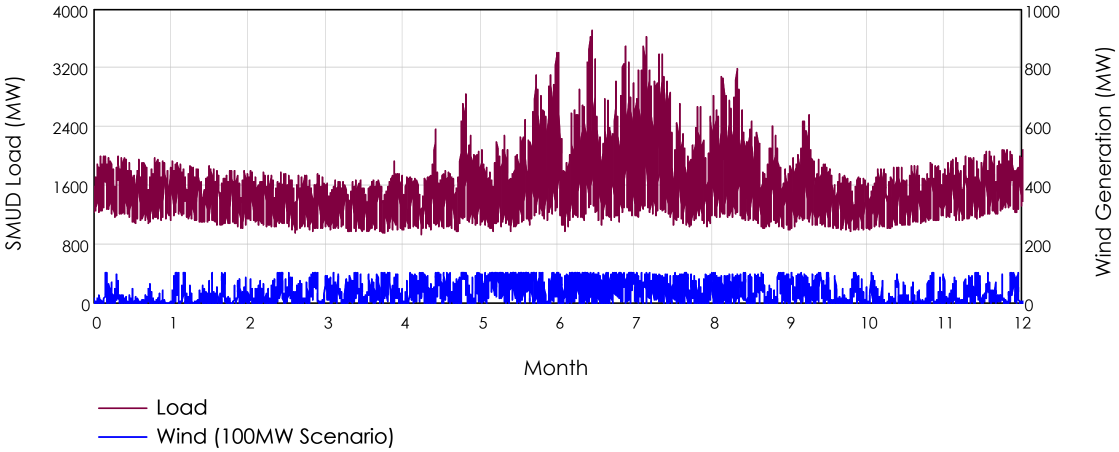


Figure 21. Wind generation and SMUD load for Case 1

Source: EnerNex Corporation

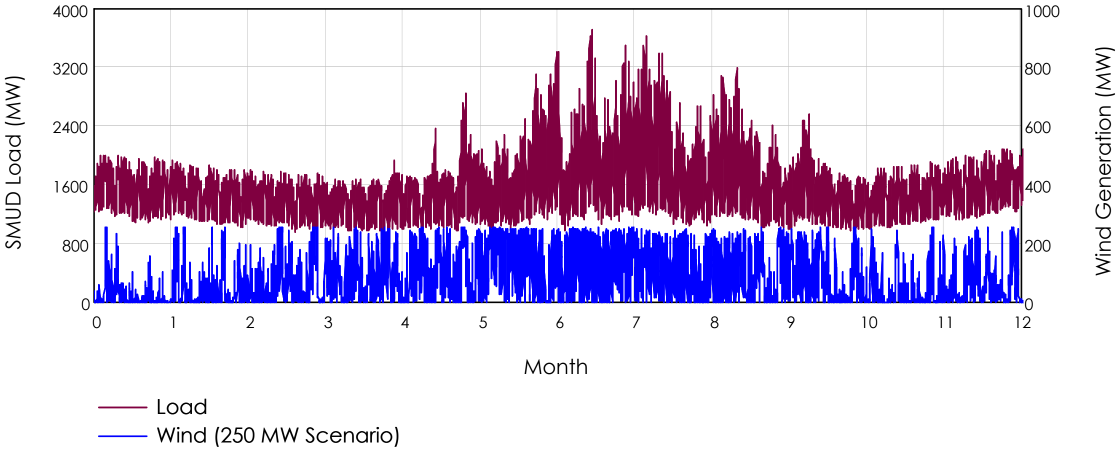


Figure 22. Wind generation and SMUD load for Case 2

Source: EnerNex Corporation

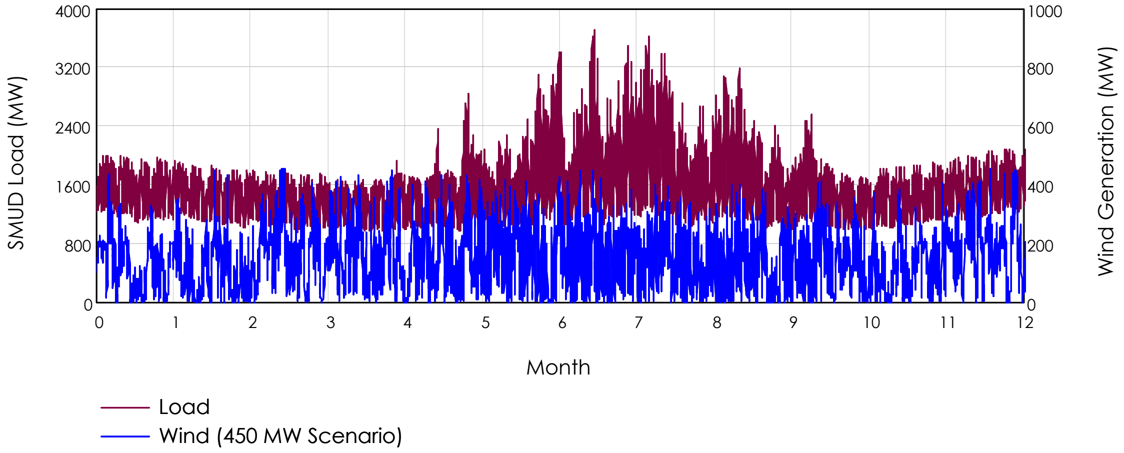


Figure 23. Wind generation and SMUD load for Case 3

Source: EnerNex Corporation

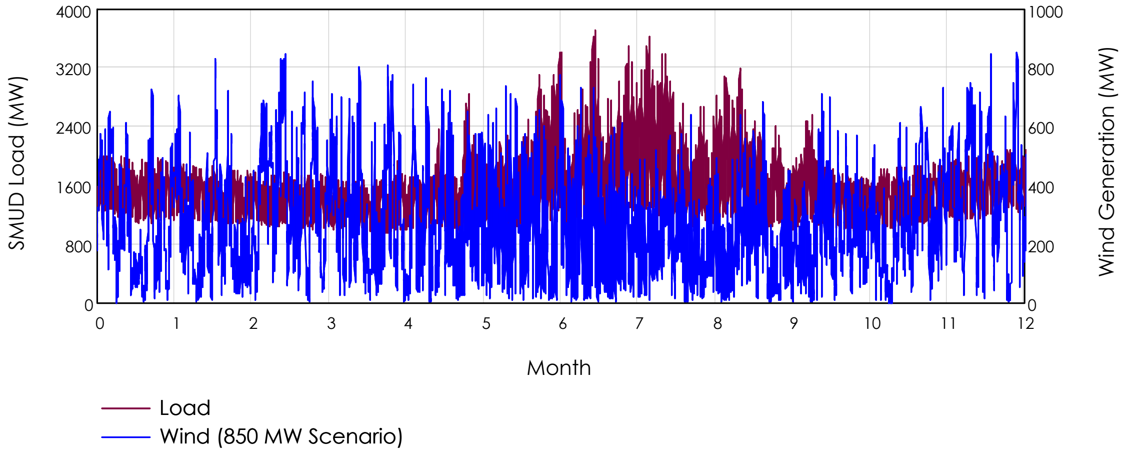


Figure 24. Wind generation and SMUD load for Case 4

Source: EnerNex Corporation

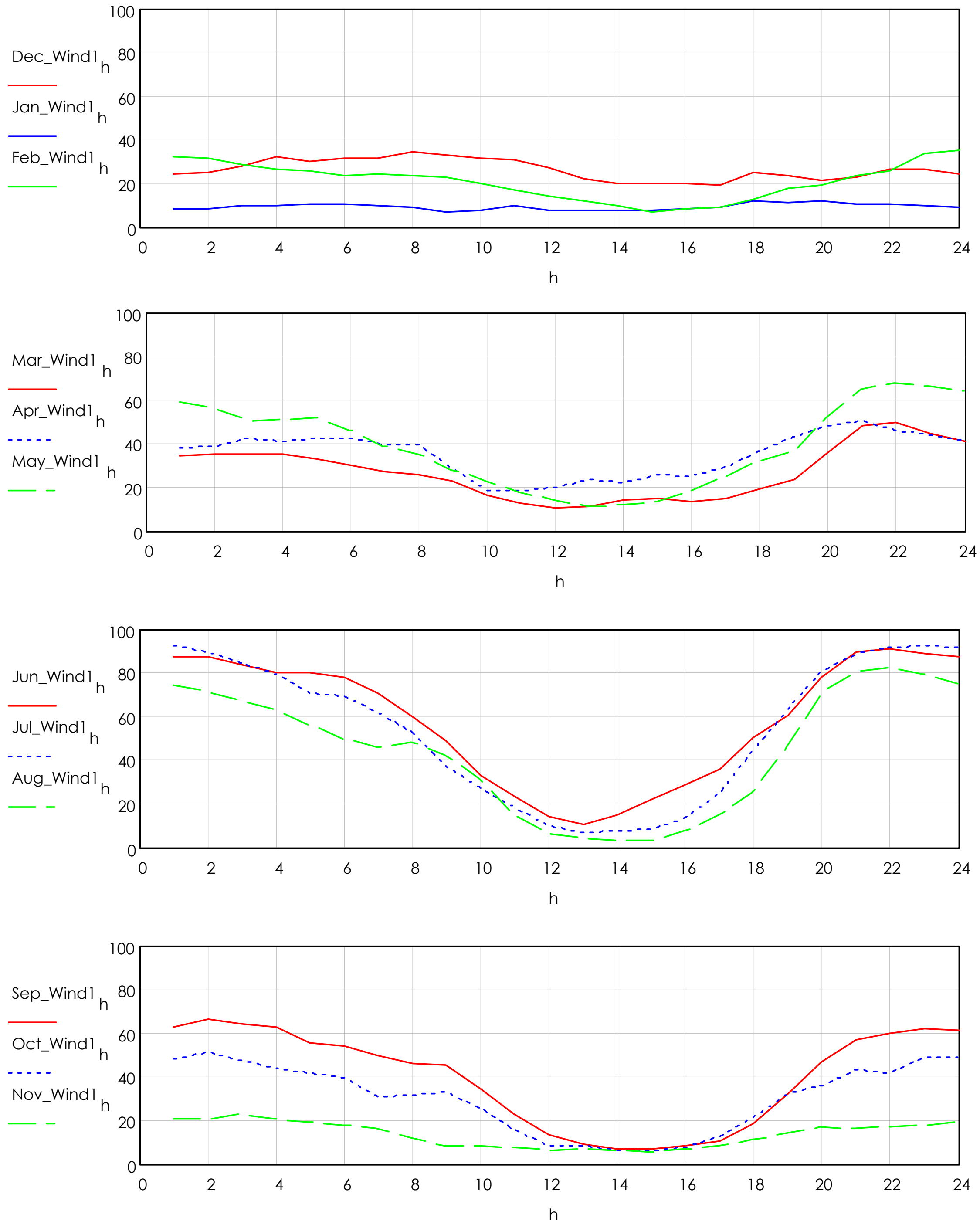


Figure 25. Average daily profiles by season for Case 1 (100 MW)

Source: EnerNex Corporation

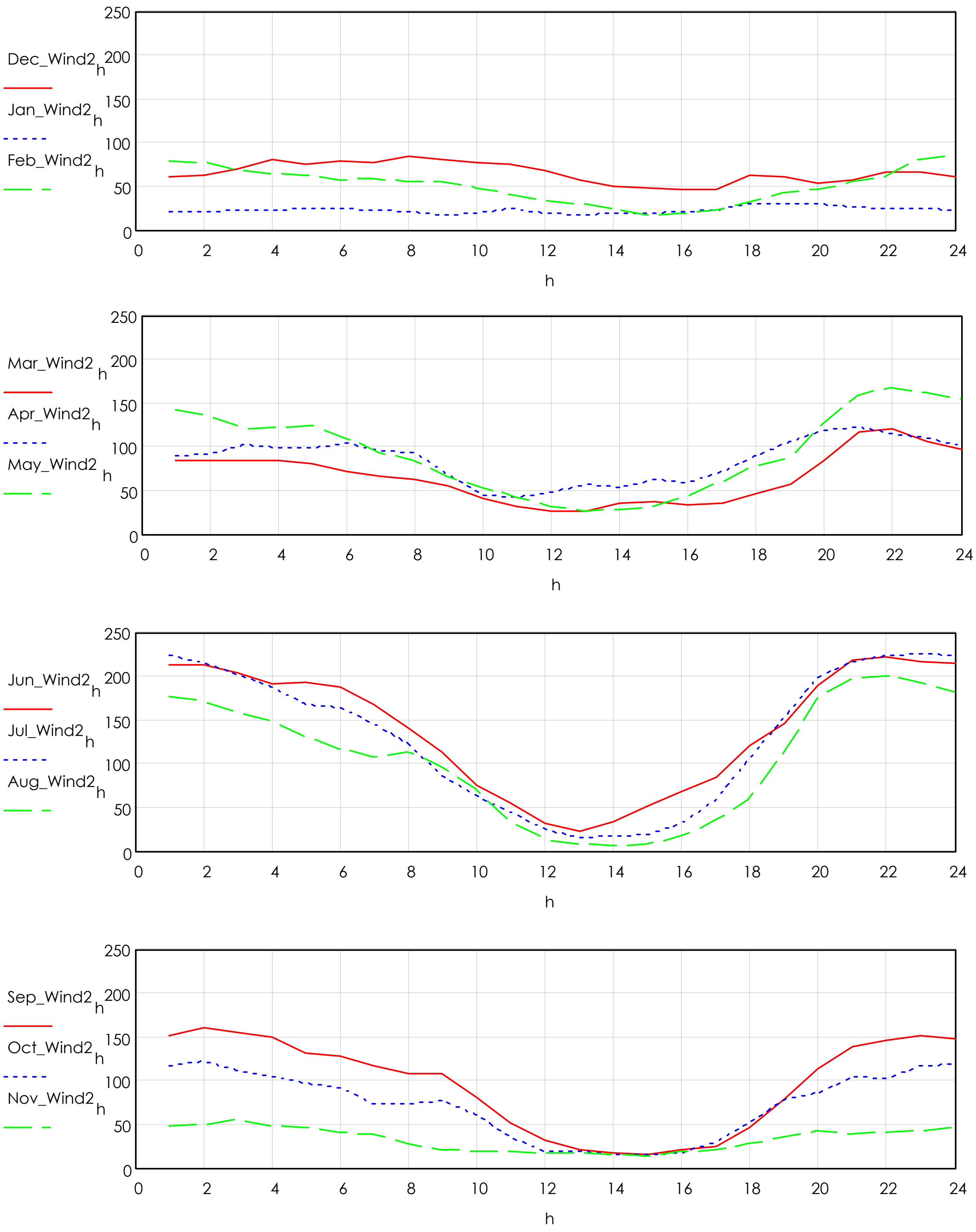


Figure 26. Average daily profiles by season for Case 2 (250 MW)

Source: EnerNex Corporation

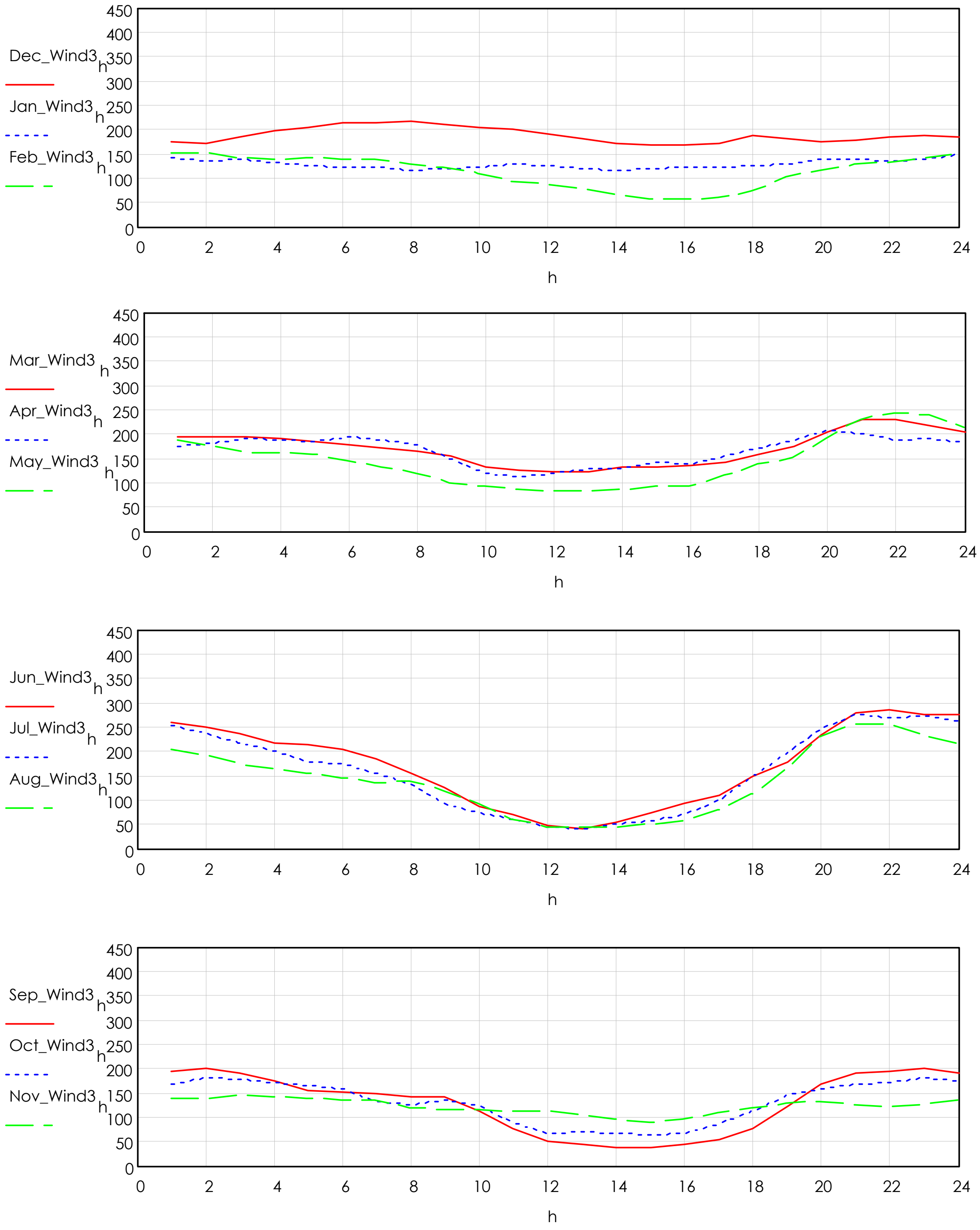


Figure 27. Average daily profiles by season for Case 3 (450 MW)

Source: EnerNex Corporation

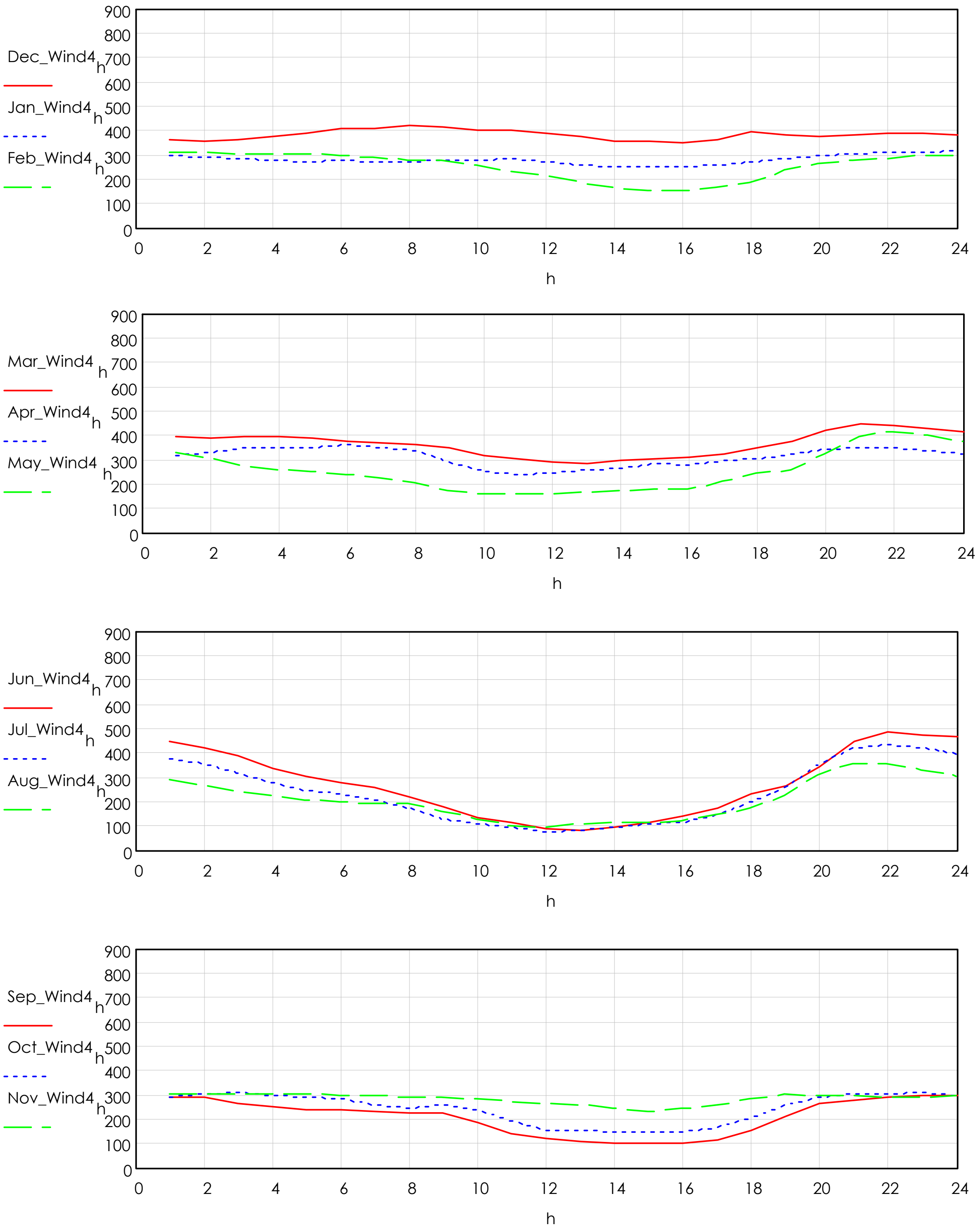


Figure 28. Average daily profiles by season for Case 4 (850 MW)

Source: EnerNex Corporation

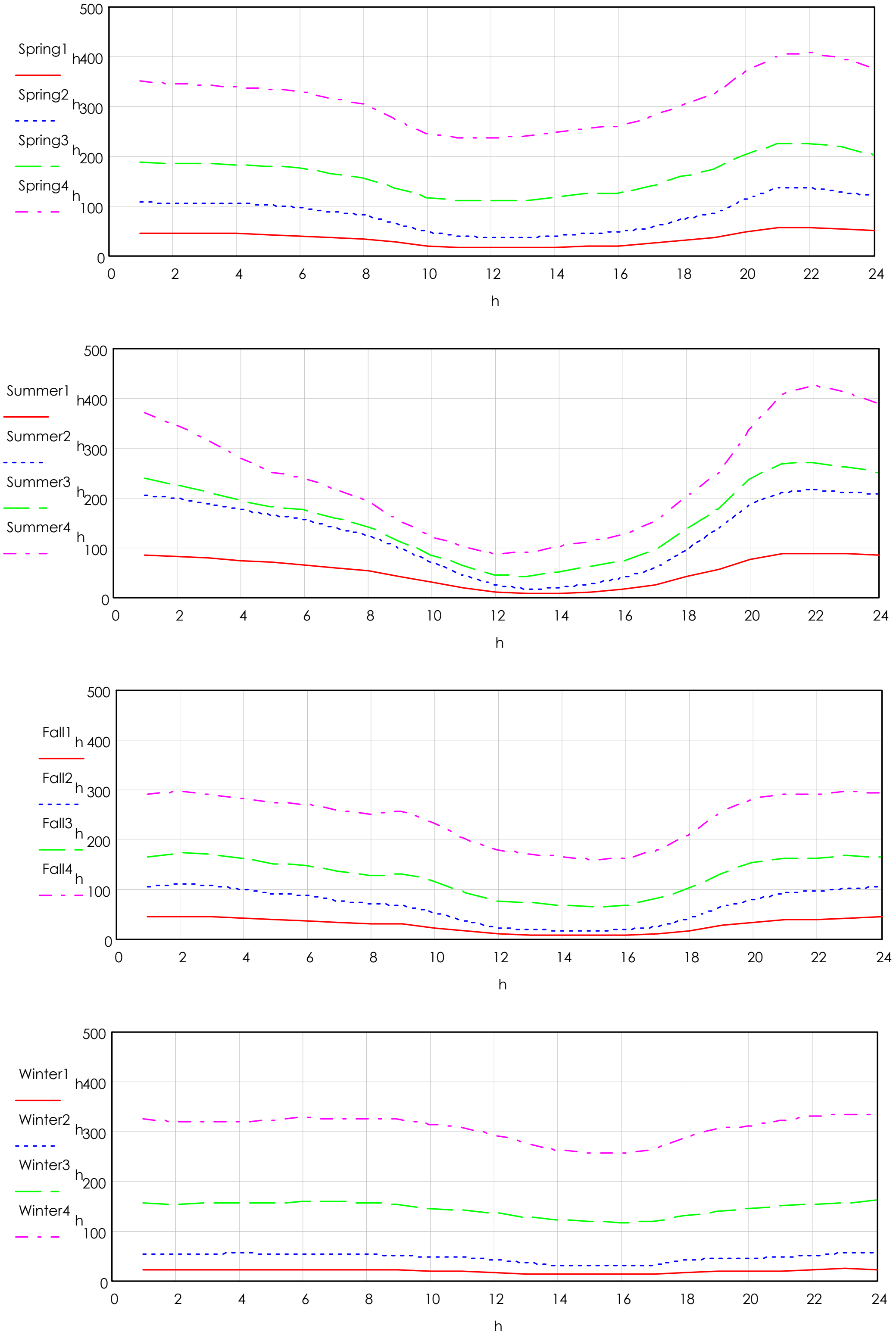


Figure 29. Average daily profiles by season and by case for 2003 wind generation

Source: EnerNex Corporation

Sample time series data from each season are shown in Figure 30 through Figure 33.

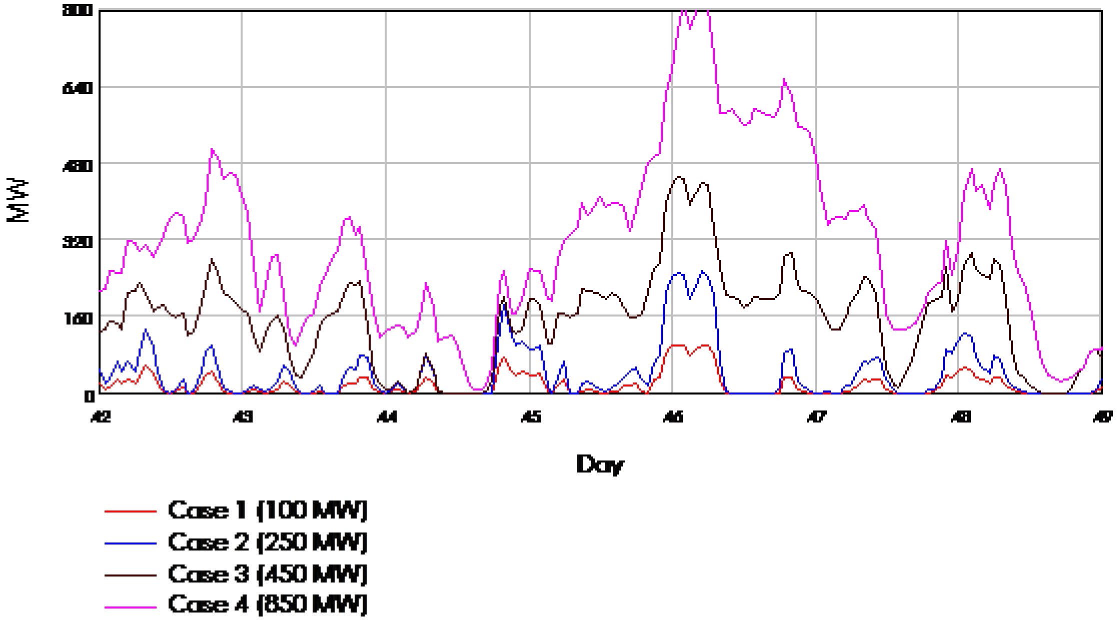


Figure 30. Wind generation profiles–sample winter week

Source: EnerNex Corporation

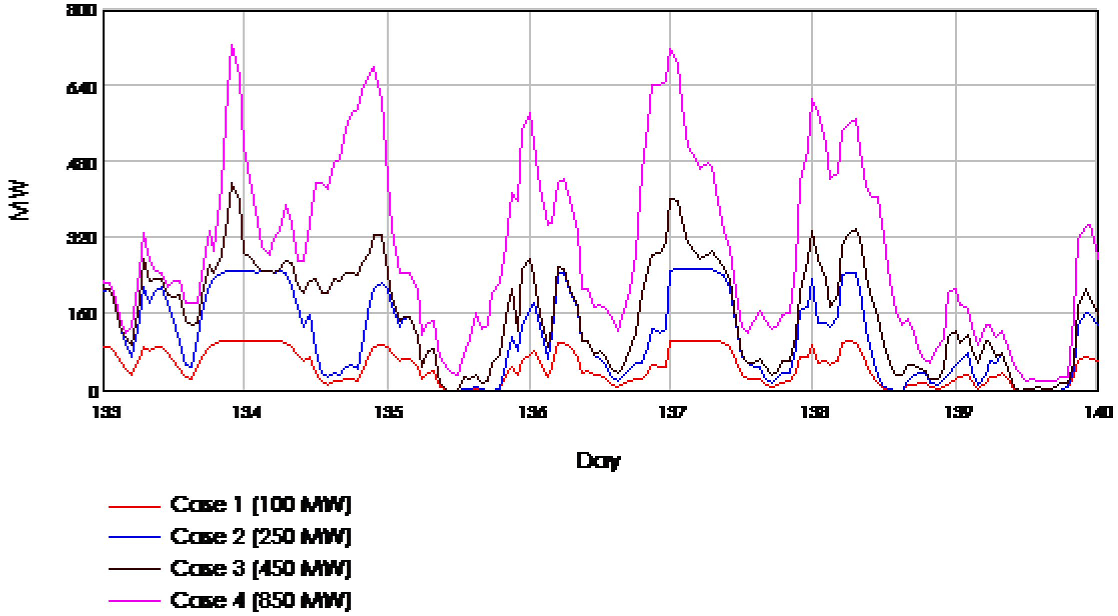


Figure 31. Wind generation profiles–sample spring week

Source: EnerNex Corporation

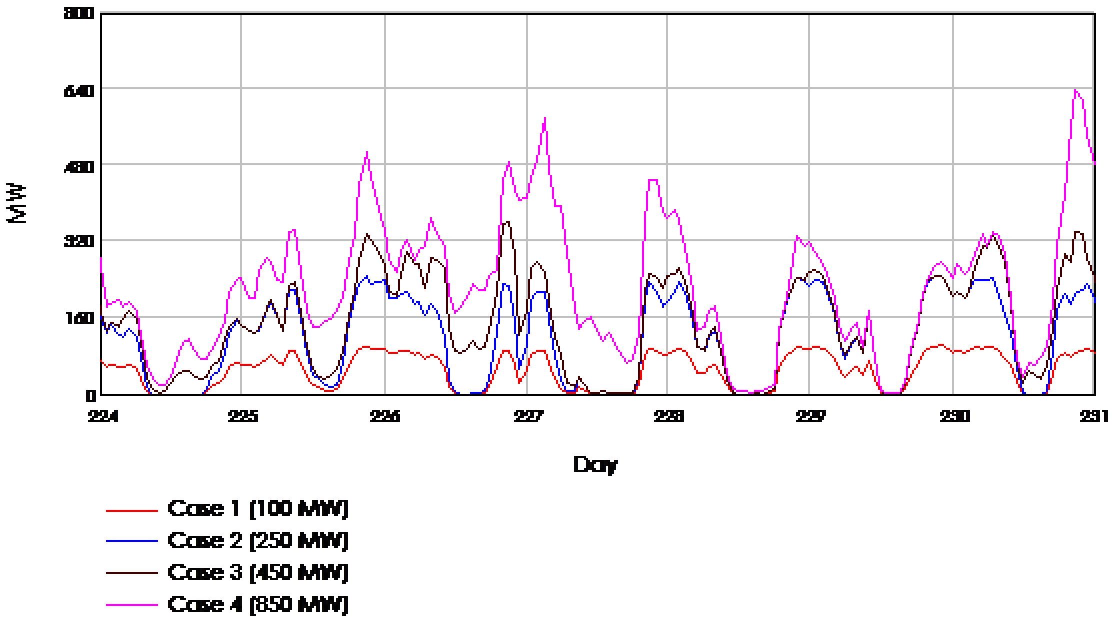


Figure 32. Wind generation profiles–sample summer week

Source: EnerNex Corporation

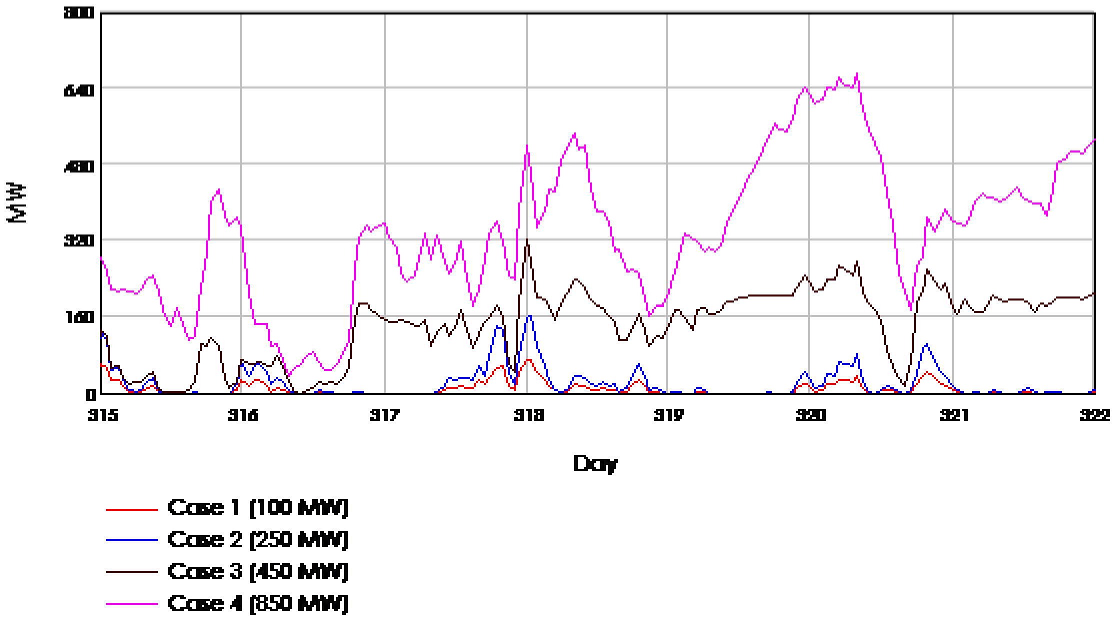


Figure 33. Wind generation profiles–sample autumn week

Source: EnerNex Corporation

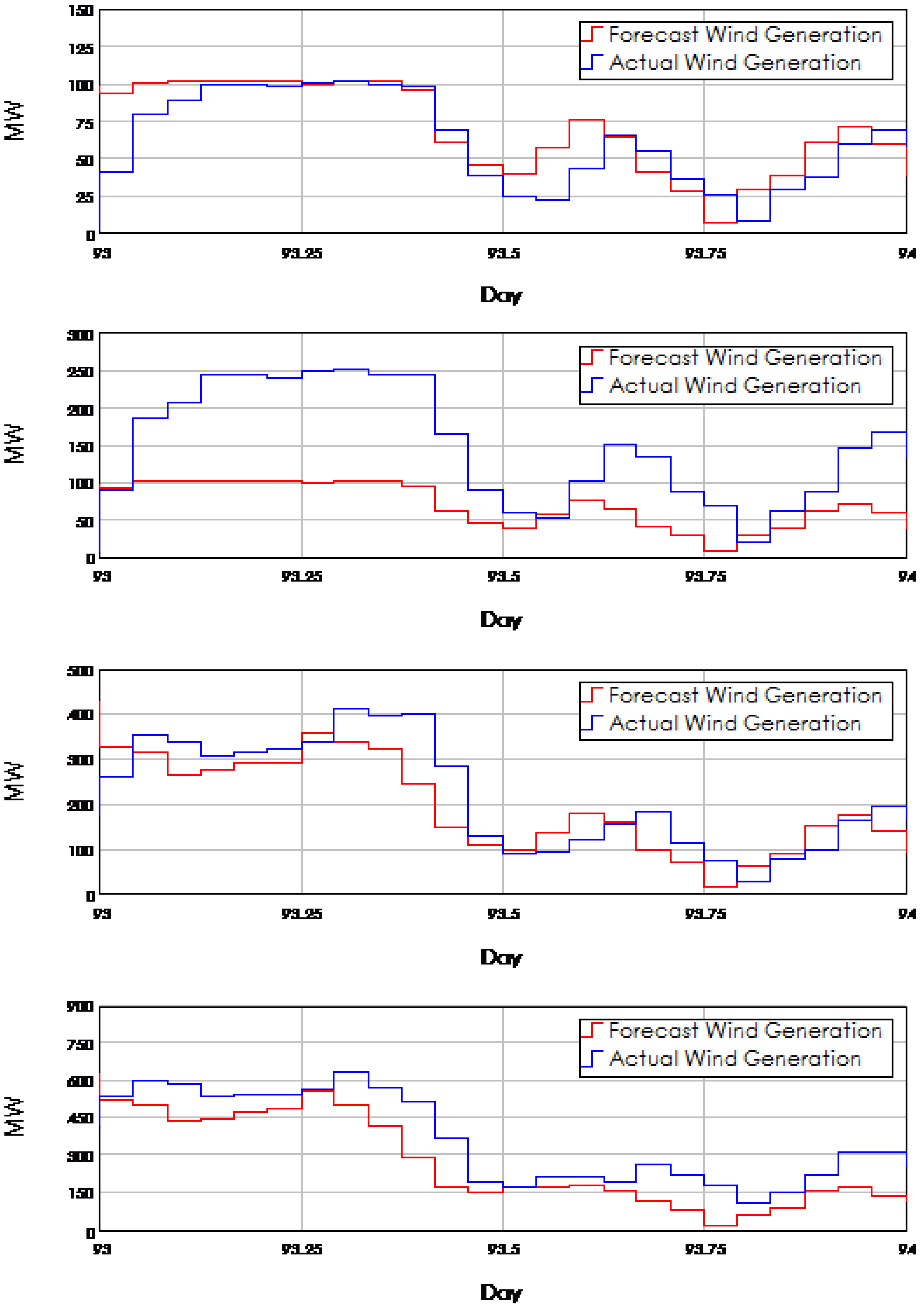


Figure 34. Forecast Wind vs. Actual wind generation for a spring day

Source: EnerNex Corporation

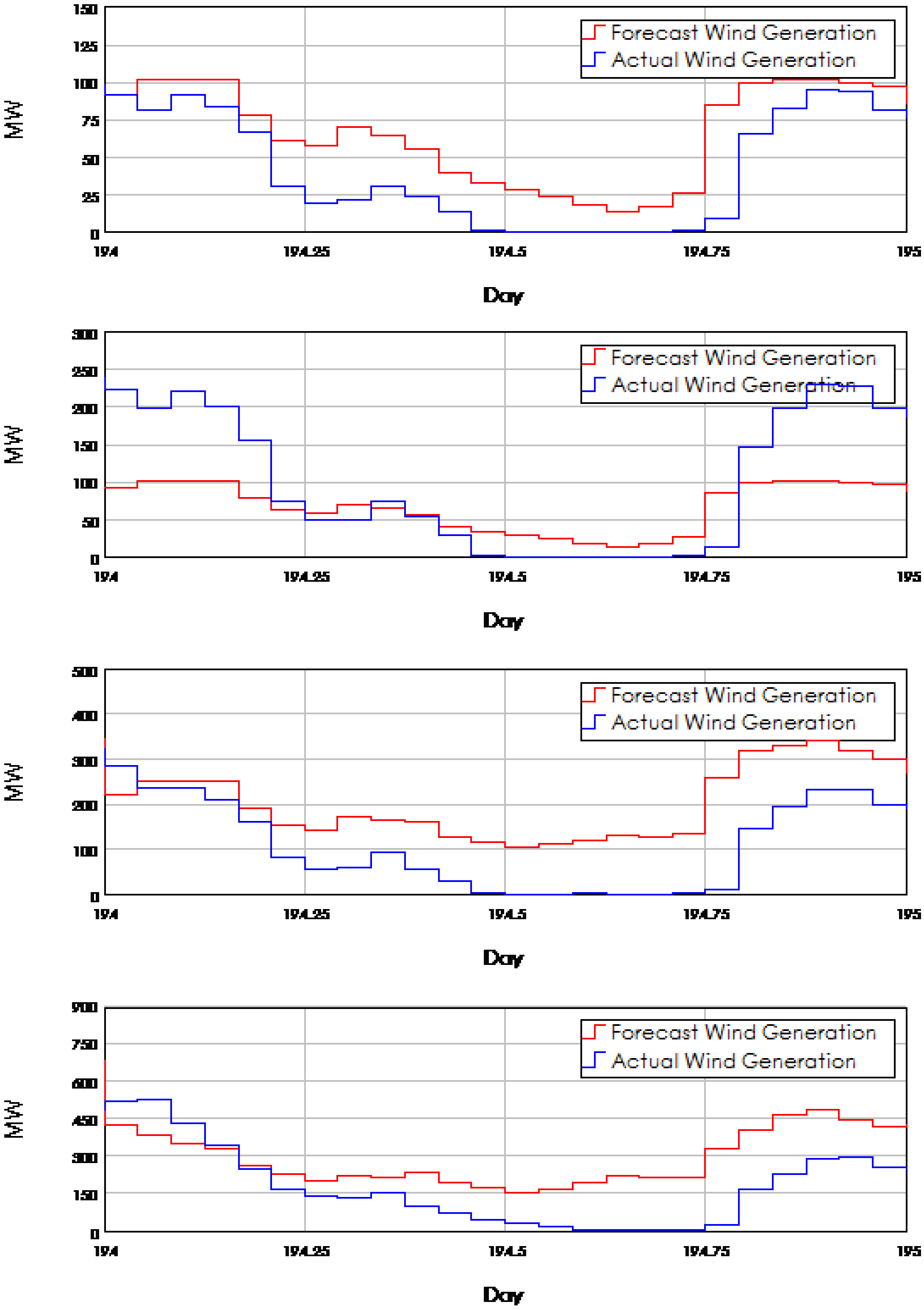


Figure 35. Forecast Wind vs. Actual wind for summer day

Source: EnerNex Corporation

3.2 Task 2–SMUD System Model

Task 2 resulted in the creation of system models for reliability and unit commitment analysis. The authors used the reliability model in Task 3 to determine the additional load carrying capability of the system with the wind energy supplied. The unit commitment model was used in Task 5 to model hourly simulations to determine the relative variable and integration cost for a number of case sets.

3.3 Task 3–Calculation of Equivalent Load Carrying Capacity

3.3.1 ELCC Calculation for Year 2011

The research team calculated LOLE calculations for the different cases using the recursive unit addition algorithm. The capacity of the four fictitious generating units has been adjusted to have LOLE of 24 hours in 10 years. Results for different cases are shown in Figure 36.

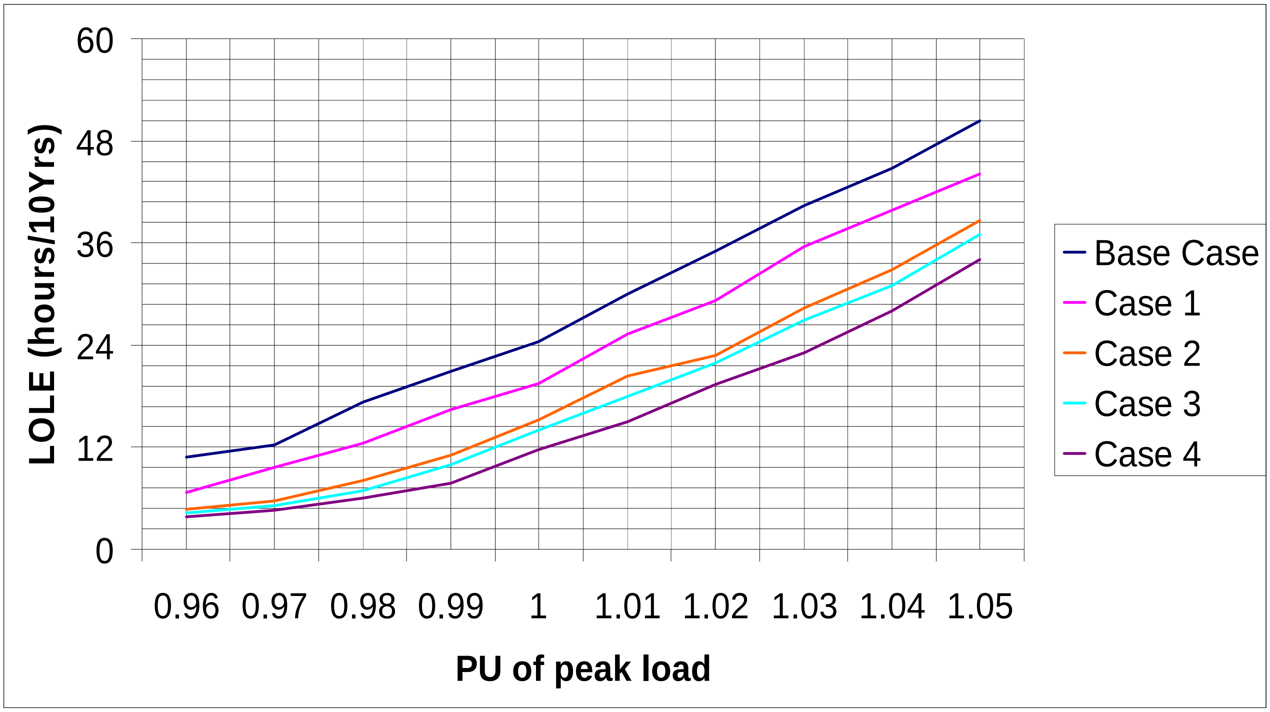


Figure 36. LOLE calculation for different yearly peak load values in per unit of year 2011 base case peak load

Source: EnerNex Corporation

To maintain same level of reliability (LOLE=24 hours/10 years), ELCC is calculated using the above chart as explained previously. Results are given in Table 19.

Table 19. ELCC calculations for year 2011

Wind case number	Increase in load (in pu of year 2011 max load =3721 MW)	The amount of extra load that can be served while maintaining same reliability level in MW	Wind rated power	ELCC %
case1	1.0075	27.9	100	27.91045
case2	1.0225	83.7	250	33.49254
case3	1.025	87	450	19.33333
case4	1.0325	88	850	10.35294

Source: EnerNex Corporation

3.3.2 ELCC Calculation for Year 2013

LOLE calculations for different cases have been calculated using the recursive unit addition algorithm. The capacity of the four fictitious generating units has been adjusted to have LOLE of 24 hours in 10 years. Results for different cases are shown in Figure 37.

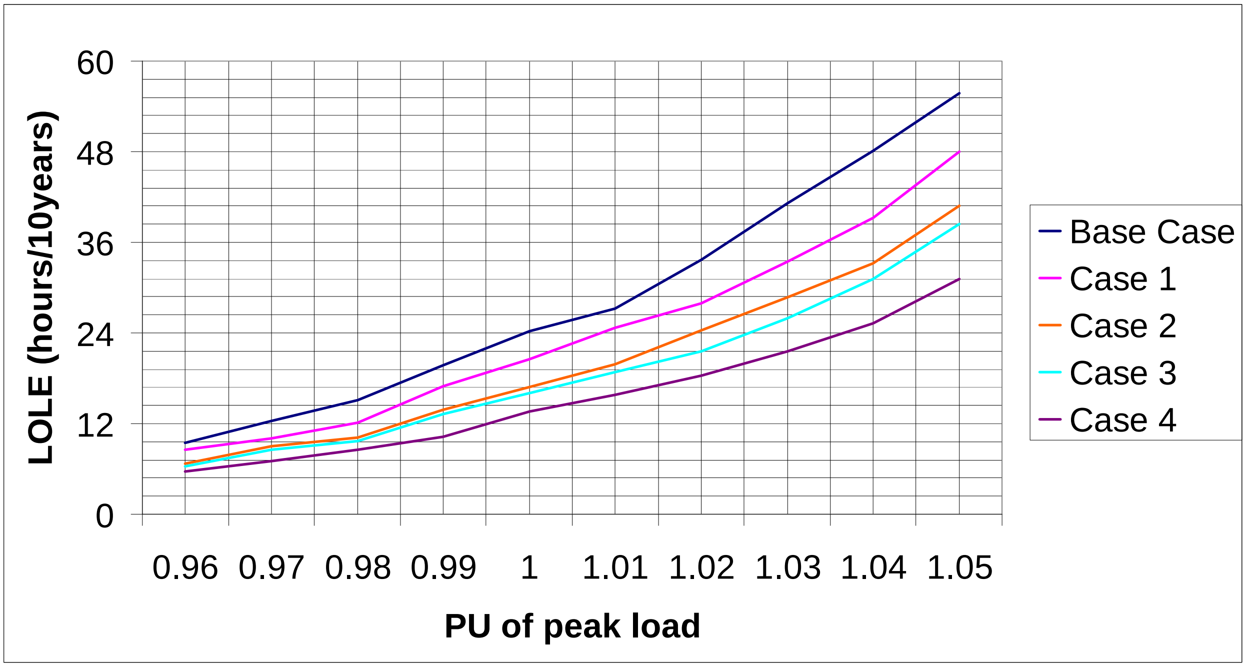


Figure 37. LOLE calculation for different yearly peak load values in per unit of year 2013 base case peak load

Source: EnerNex Corporation

To maintain same level of reliability (LOLE=24 hours/10 years), ELCC is calculated using the above chart as explained previously. Results are given in Table 20.

Table 20. ELCC calculations for year 2013

Wind case number	Increase in peak load (in pu of year 2013 max load =3615 MW	The amount of extra peak load that can be served while maintaining same reliability level (MW)	Wind rated power	ELCC %
Case1	1.0075	27.12	100	27.11
Case2	1.02	72.31	250	28.92
Case3	1.025	90.38	450	20.09
Case4	1.0375	135.58	850	15.95

Source: EnerNex Corporation

3.3.3 Summary

1. Five different power generation cases for the SMUD system have been studied in this report: a base case where wind power generation is not considered and four different scenarios of wind generation for SMUD with nameplate values of 102 MW, 252 MW, 453 MW, and 855 MW, respectively.
2. Historical metrological wind data has been used to devolve wind speed forecast models for the proposed wind power plant locations. Based on these models, the authors created an hourly time series of wind power generation for each case for years 2011 and 2013 based on the forecast wind speed.
3. Hourly load values for SMUD in years 2011 and 2013 have been forecast based on the actual hourly load values in years 2003 and 2004, respectively. In the reliability calculations, the wind power has been modeled as a load modifier, i.e. net load at any hour equals the forecast load value minus the forecast wind generation value at this hour.
4. Capacity factor has been calculated for the four wind generation cases for each year with value range from 31 percent to 37 percent when considering wind generation during the whole year. When considering wind generation during the highest 17 hourly load values, capacity factor varies significantly for different cases with value range from 10 percent to 50 percent.
5. Availability data of SMUD generating units from 1995 to 2001 has been used to calculate FOR and failure and repair rates for each unit.
6. Four fictitious generating units with FOR of 0.02 have been added to SMUD generating units to represent the amount of power that SMUD can import from transmission network from other control areas through firm contracts. The authors adjusted power generation and FOR of these units to achieve a reliability criterion of hourly LOLE of 2.4 hours per year, i.e. 24 hours per 10 years.
7. The system total generating capability is 4135 MW. That represents 11.12 percent generating reserve compared to the peak load of 3721 MW.
8. Capacity factor calculation is not sufficient to judge the benefits of adding wind generation to a certain system. Adding wind generation leads to increase the

overall generation system adequacy. This increase in system reliability can be quantified by calculating the ELCC. This value represents the extra amount of load, as a percentage of installed wind generation capacity, the generating system can supply due to the addition of new wind generation while maintaining the same level of generation reliability of LOLE of 24 hours per 10 years.

9. The recursive unit addition algorithm has been used to perform adequacy analysis of the SMUD generating system. The authors performed LOLE calculations for the same per unit hourly curve with different peak values in per unit of the base case peak load value. These calculations have been repeated for all five cases for year 2011.
10. The results of the LOLE calculations have been used to graph the relation between LOLE and the per unit peak values. Form these graphs, ELCC has been calculated for each case. For year 2011, the ELCC values are 27.9 percent, 33.5 percent, 19.3 percent and 10.3 percent for Cases 1 to 4, respectively. For year 2013, the ELCC values are 27.1 percent, 28.9 percent, 20.1 percent and 15.9 percent for Cases 1 to 4, respectively.

3.4 Task 4–Analysis of Intra-Hour Wind Generation Impacts

3.4.1 Reserve Requirements for Managing Incremental Variability

Based on the procedures developed in the previous chapter, the additional reserve requirements due to the incremental variability introduced by wind can be calculated.

Using 10-minute average load data, a rule is devised to calculate the range in which generation must be moved inside the hour to follow the load deviations from the hourly average. After some experimentation, the project team found that an up/down range defined to be 22.5 percent of load change from the current hour to the next, assuming that the MAE of the next hour load forecast is 1 percent and covers 98.0 percent of the 10-minute deviations from the hourly average value to within the SMUD L10 of 35.84 MW for the one year of data.

The profile varies by hour, but the year has an average value of 14.6 MW.

Figure 38 shows how this works for a typical period out of the sample.

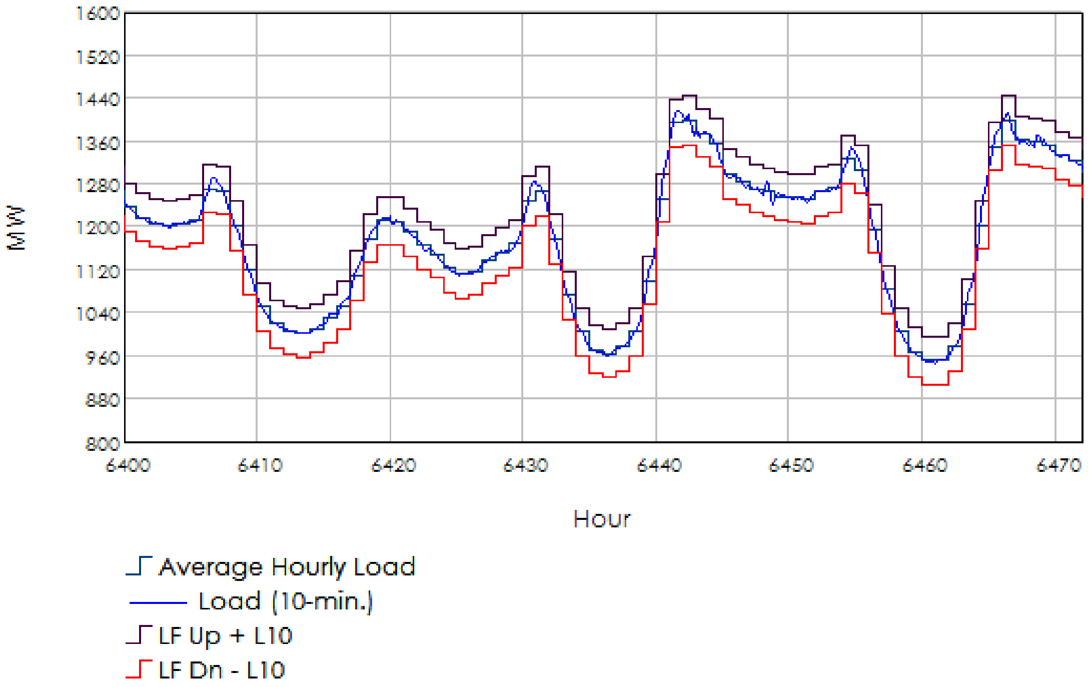


Figure 38. 10-minute load following

Source: EnerNex Corporation

From that baseline, the next objective is to devise a new rule that works with wind generation on the system. In essence, there must be enough load-following capability to encompass the net deviations of load and wind generation at 10-minute intervals. Initially it is assumed that wind generation can be forecast perfectly, so that the hourly average value from which the deviations are computed is the net of the hourly average load and the hourly average wind.

The amount of wind generation change over an hour is selected as the metric for characterizing wind generation variability. There are most certainly others that could be developed, such as using statistics of wind generation variability at the 10-minute resolution, but the selected approach lends itself well to characterization from the data at hand.

Using the hourly average wind generation data, the variability over one hour (i.e. change in average production from one hour to the next) is computed for 10 deciles of production. The results for the SMUD wind generation scenarios developed from the WindLogics meteorological simulations are shown in Figure 39. The curves show that the maximum variability occurs in the mid-range of the aggregate nameplate rating for the scenario.

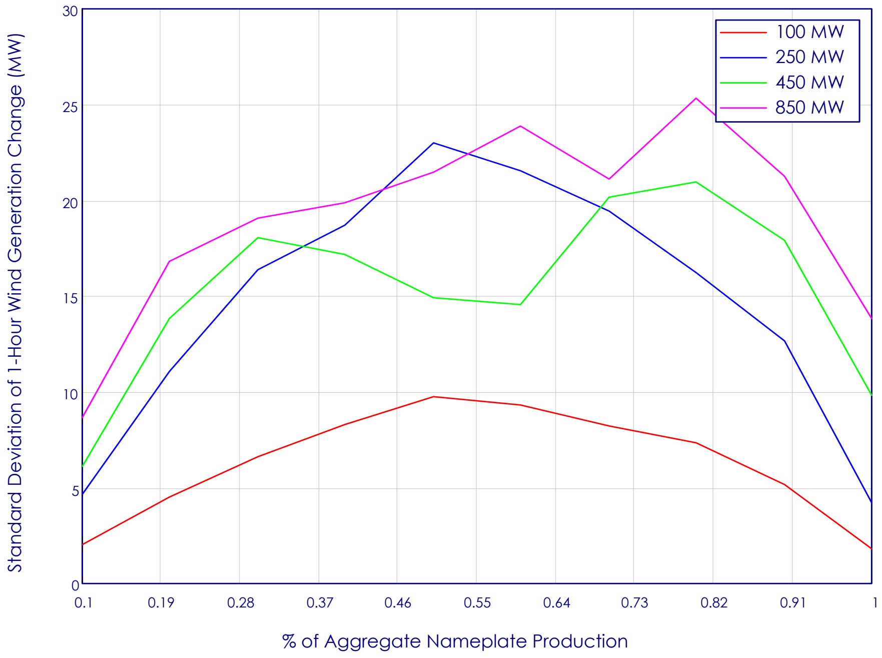


Figure 39. Standard deviation of one-hour wind change as a function of production

Source: EnerNex Corporation

To facilitate the application of the rule on an hourly basis, the empirical results from Figure 39 are approximated as quadratic expressions, with the input to the expression being the current hour's average production. In this first example, it is assumed that the reserve planning for the hour is performed just prior to the start of the hour, so that the average production is from H-1 and the amount of change predicted for H.

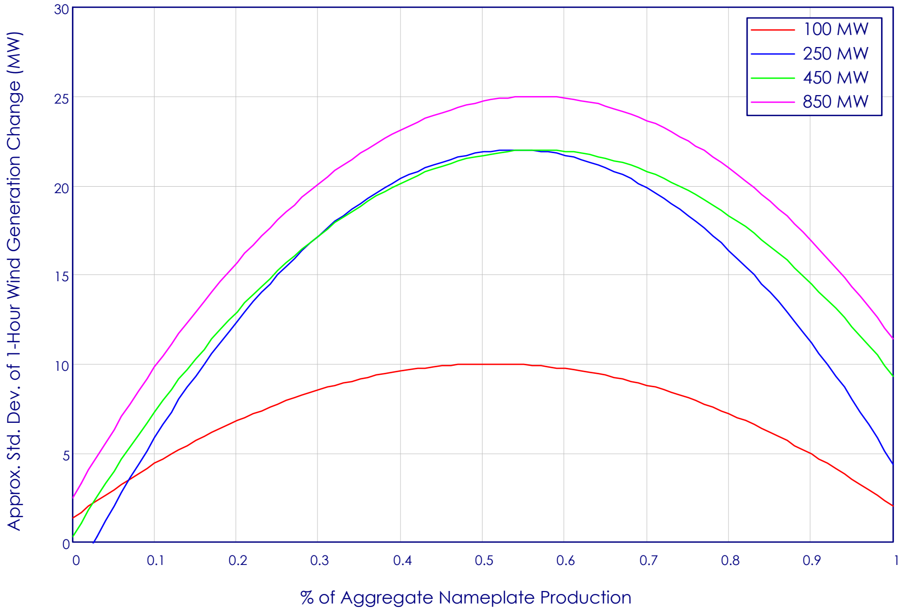


Figure 40. Approximate standard deviation of one-hour wind change as a function of production

Source: EnerNex Corporation

The quadratic expressions are:

$$f1'(x) := 10 - \frac{(x-51)^2}{300}$$

$$f2'(x) := 22 - \frac{(x-135)^2}{750}$$

$$f3'(x) := 22 - \frac{(x-255)^2}{3000}$$

$$f4'(x) := 25 - \frac{(x-450)^2}{9000}$$

where f1` through f4` correspond to the 100 MW, 250 MW, 450 MW, and 850 MW scenarios, respectively.

The load-following rules for each wind scenario are of the form

$$F1_h := F0_h + 1.0 \cdot f1'\left(HWind1_{h-1}\right)$$

$$F2_h := F0_h + 1.0\, f2'\left(HWind2_{h-1}\right)$$

$$F3_h := F0_h + 1.0 \cdot f3'\left(HWind3_{h-1}\right)$$

$$F4_h := F0_h + 1.0 \cdot f4'\left(HWind4_{h-1}\right)$$

where the variable in the expression is the current hour average wind generation (h-1 because the authors are planning for hour h), the quadratic constants are from the empirical analysis described previously, and F0 is the load following requirement for load alone, calculated previously

The coefficient k is adjusted so that the number of CPS2 “violations” is the same as for the case with no wind. Running these experiments for each wind generation scenario, it was found that a coefficient of 1.0 (as shown) provided about the same level of performance for each wind generation scenario.

Figure 41 depicts typical hourly load following “bands” shown with average hourly and 10-minute control area demand. While most 10-minute values are well inside these bands, a few violations can be seen in this 72-hour record.

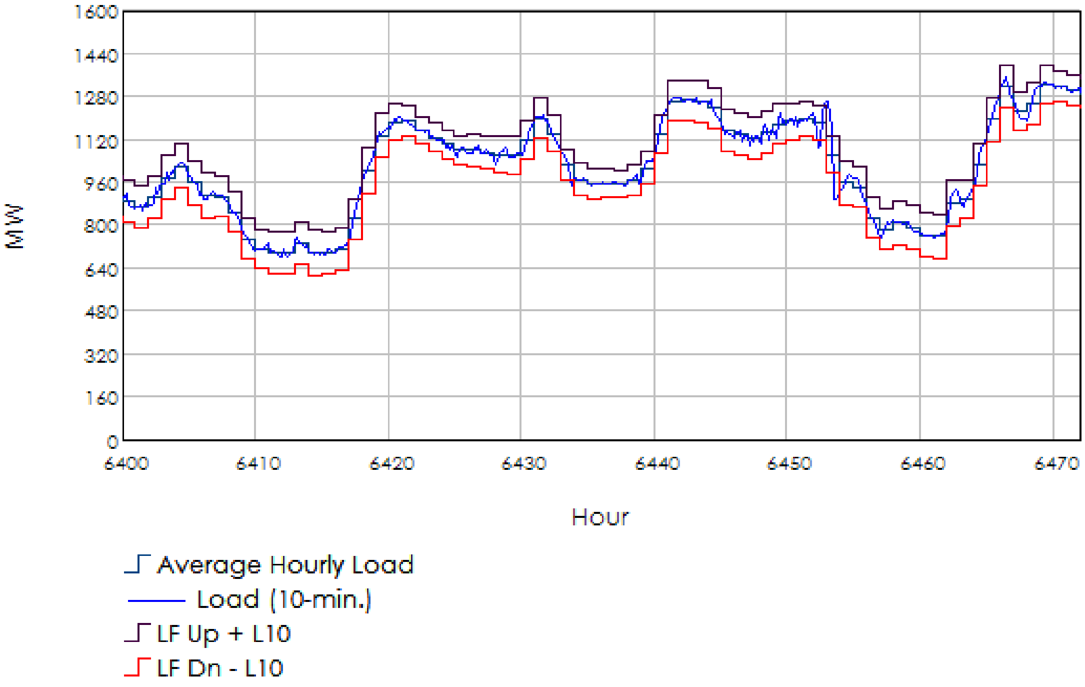


Figure 41. Calculated load following requirements

Source: EnerNex Corporation

The average load-following capability over all hours of the sample year for the four wind generation scenarios are documented in Table Table 21

Table 21. Load following requirements by wind penetration level

Scenario	*Average Hourly LF Limits (+/-)*	*Increment for Wind (+/-)*
Load only	14.6 MW	-
100 MW	18.4 MW	3.8 MW
250 MW	26.4 MW	11.8 MW
450 MW	39.8 MW	15.2 MW
850 MW	46.0 MW	31.4 MW

Source: EnerNex Corporation

Impacts of Short-Term Forecast Error on Real-Time Operations

The analysis for effects of incremental variability assumes that the reserves for the hour are planned on the basis of perfect knowledge of the next hour average load and wind generation. This is the situation with minimal uncertainty and that relates mostly to the real-time operation of the system to compensate for inside-the-hour variations from some constant average value. In reality, there are operational decisions made some hours prior to this hour that will affect the generation flexibility that is needed to manage the control area.

If reserves must be allocated an hour or more before the operating hour, the known wind generation at that time may be substantially different than in the hour in question. This could impact the projected variability, as it is a function of the current production level.

Load forecast errors also contribute to the schedule deviations. In the illustration to follow, it is assumed that the MAE of the two-hour-ahead load forecast is a normally distributed random variable with a standard deviation of 1.25 percent, which results in a mean absolute error of 1.0 percent. Further, it is assumed that the load forecast error is uncorrelated with the short-term wind generation forecast error.

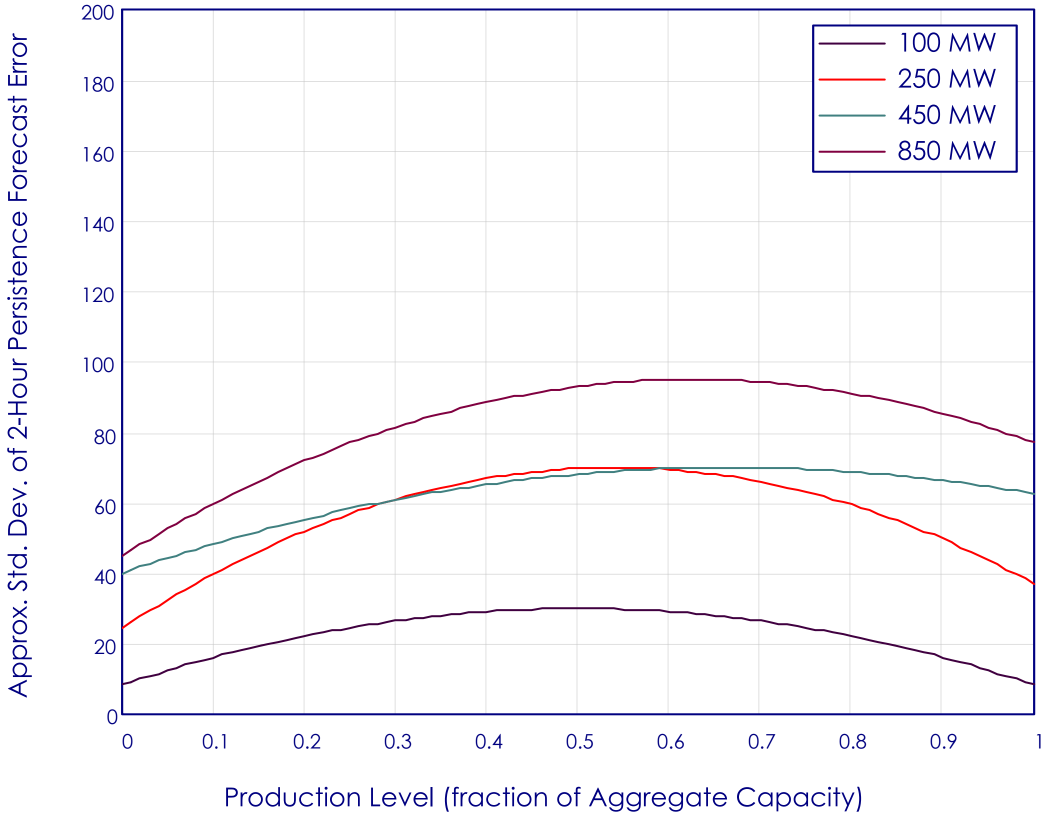


Figure 42. Standard deviation of persistence forecast error over a two hour horizon for the four wind generation scenarios.

Source: EnerNex Corporation

The authors added quadratic formulas for the curves of Figure 42 to the equations for hourly reserves, and adjusted the coefficients to achieve the same control performance as for load variability alone.

The new load-following equations that consider the lead time for hourly transactions and the associated uncertainty in both load and wind generation are shown below:

$$F0'_h := F0_h + 0.8 \cdot \sigma_{stlfe}$$

$$F1'_h := F1_h + 0.8 \cdot FE1\left(HWind1_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F2'_h := F2_h + 1.8 \cdot FE2\left(HWind2_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F3'_h := F3_h + 1.8 \cdot FE3\left(HWind3_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

$$F4'_h := F4_h + 2.0 \cdot FE4\left(HWind4_{h-2}\right) + 0.8 \cdot \sigma_{stlfe}$$

where

F0 = the reserve requirement for managing intra-hour variability only (or F1, F2, F3, F4 for load net wind variability only)

σ_{stlfe} = standard deviation of the short-term load forecast error

FE"x" = function describing standard deviation of short-term wind generation forecast error as a function of production level, where "x" is wind generation scenario 1, 2, 3, or 4. This is to the total hourly up/down reserve requirement needed to compensate for both the intra-hour variability and schedule deviations from short-term load and wind generation forecast error.

As done with variability, the coefficients on the terms representing the forecast errors are adjusted so that the desired percentage of 10-minute deviations from the hourly average can be compensated to within SMUD's L10 value of 35 MW. Table 22 shows the average value over the year from the resulting dynamic hourly profiles.

Table 22. Total reserves for variability and schedule deviations

Case	Average Hourly Flexibility for Variability (+/-)	Average Hourly Flexibility for Variability and Schedule Deviation (+/-)
Load only	14.6 MW	26.6 MW
100 MW	18.4 MW	47.8 MW
250 MW	26.4 MW	112.9 MW
450 MW	39.8 MW	146.2 MW
850 MW	46.0 MW	201.1 MW

Source: EnerNex Corporation

The direction of the forecast error will be known just prior to the operating hour. Intra-hour variability, as computed earlier in this study, must still be covered and is not affected by the forecast error. So, it seems that the real-time operators would know at the beginning of the operating hour how the scheduling error would impact the reserve requirements. If there is additional energy to be provided to cover the forecast error, the capacity set aside to move up would be used, with no need to retain the downward movement capability. The operating plan for the hour must be sufficient to cover both the up and down side of the forecast error.

Because it is an offset in the flat schedule for the hour, there is minimal intermingling between the component required for managing variability and that set aside to cover schedule error.

Estimated Regulation Requirements for SMUD Control Area with Increased Wind Generation

The standard deviation of the fast fluctuations in SMUD control area load, from above, is one-fifth of the stated regulation requirement or 3.6 MW. The regulation requirement for each of the wind generation scenarios can then be computed from the equation, and are shown inTable 23.

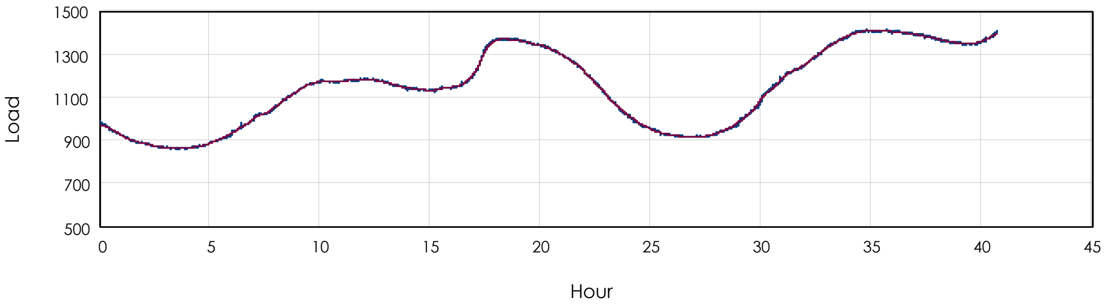
A conclusion that can be drawn from these estimates is that lower penetrations of wind generation have only a small impact on fast regulation requirements, but begin to dominate as the penetration increases.

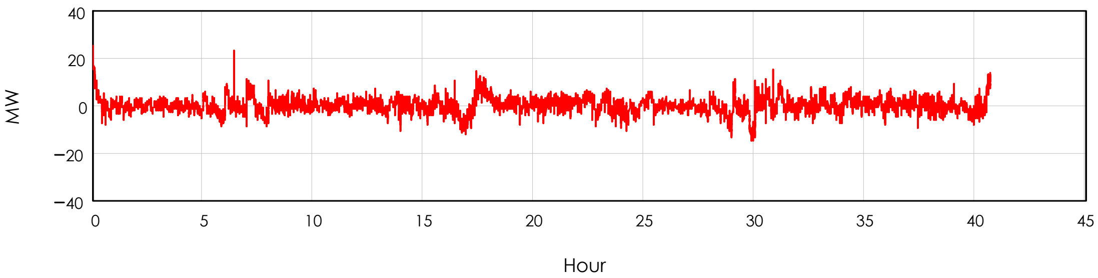
Table 23. Estimated SMUD fast regulation requirements for wind generation scenarios

Wind Generation	System Fast Regulation Requirement	Increase due to Wind Generation
0 MW (Load Only)	18.0 MW	-
100 MW	18.7 MW	0.7 MW
250 MW	19.7 MW	1.7 MW
450 MW	20.9 MW	2.9 MW
850 MW	23.1 MW	5.1 MW

Source: EnerNex Corporation

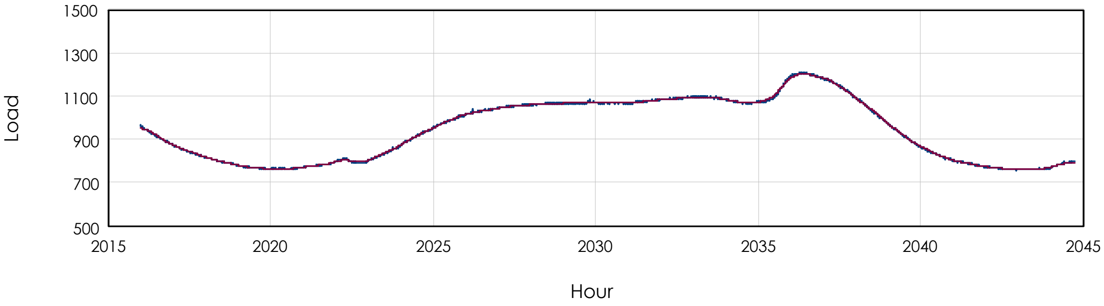
Daily Analysis Results

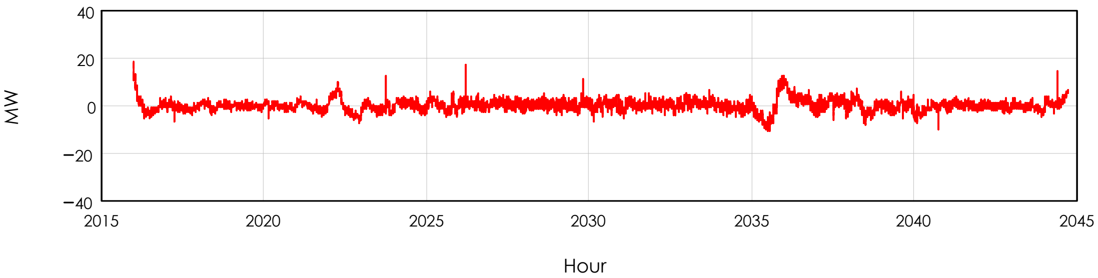




$$5\,\text{stdev}\,(Dev) = 18.4$$

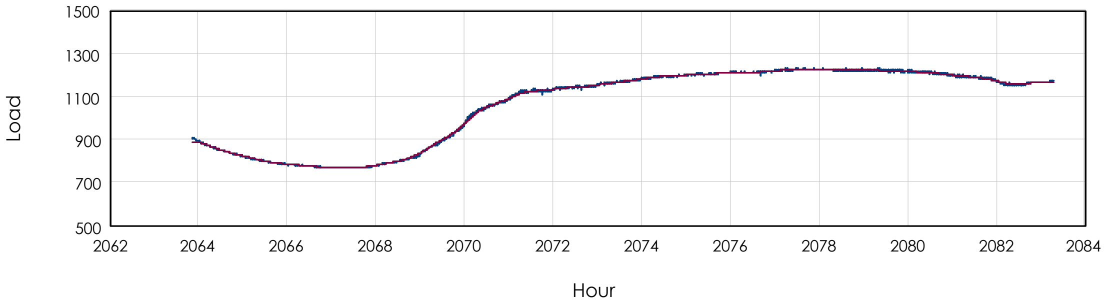
$$\frac{5\cdot\text{stdev}\,(Dev)}{\max(L1)} = 1.3\ \%$$

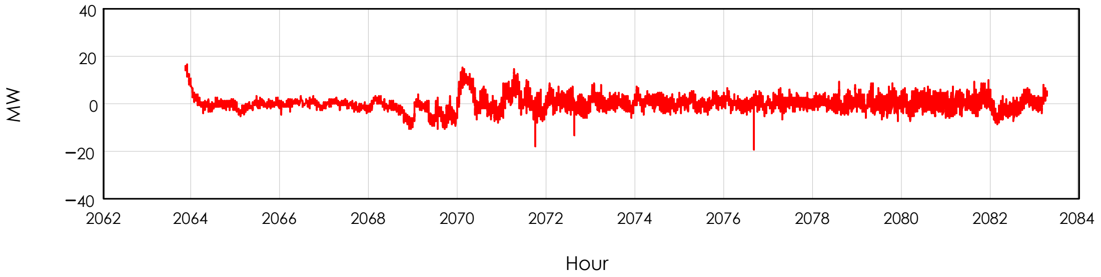




$$5\,\text{stdev}\,(Dev) = 13.0$$

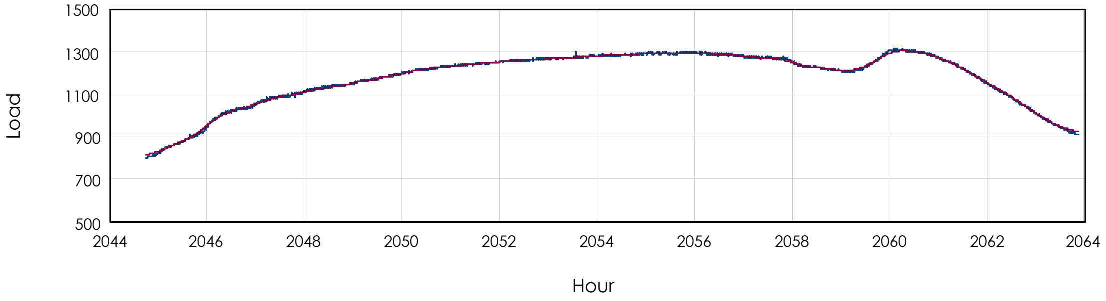
$$\frac{5\cdot\text{stdev}\,(Dev)}{\max(L1)} = 1.08\ \%$$

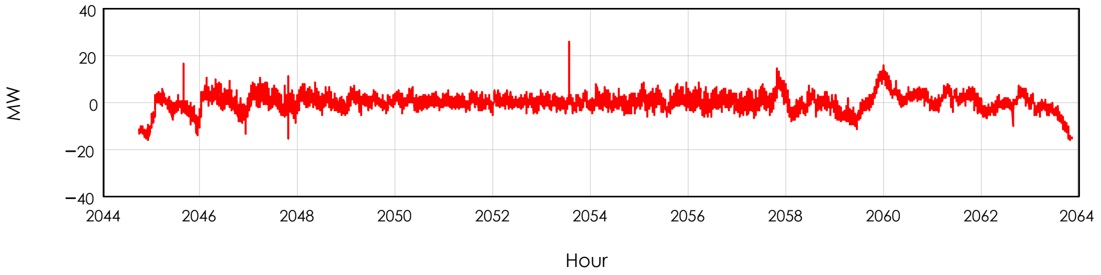




$$5\ \mathrm{stdev}\ (Dev) = 16.2$$

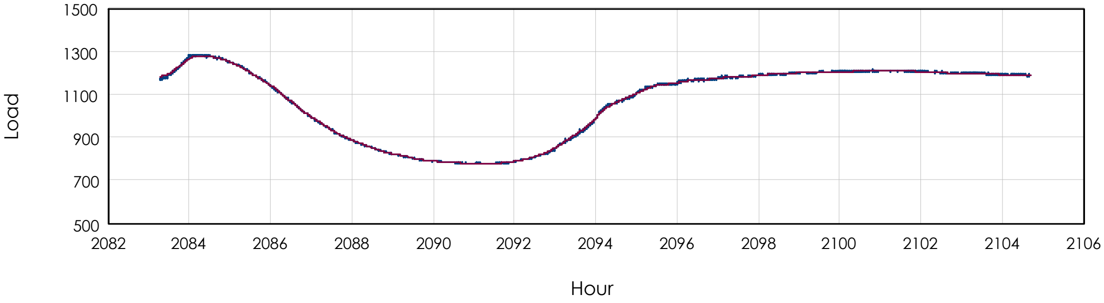
$$\frac{5 \cdot \mathrm{stdev}\ (Dev)}{\max (L1)} = 1.32\ \%$$

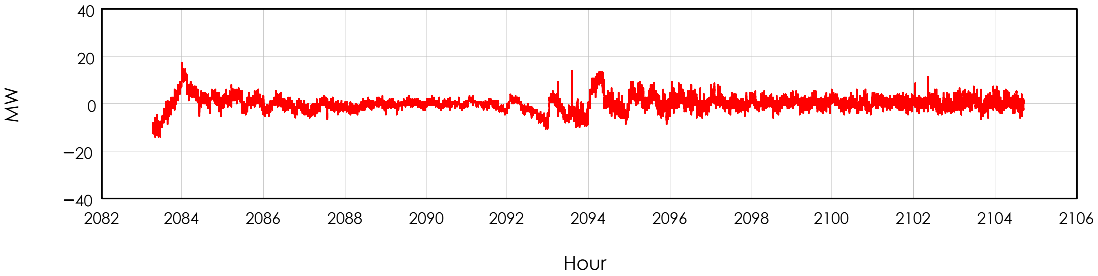




$$5\ \mathrm{stdev}\ (Dev) = 18.0$$

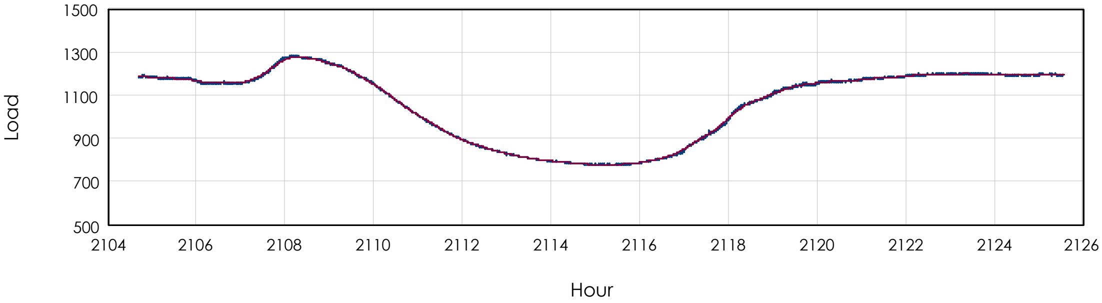
$$\frac{5 \cdot \mathrm{stdev}\ (Dev)}{\max (L1)} = 1.37\ \%$$

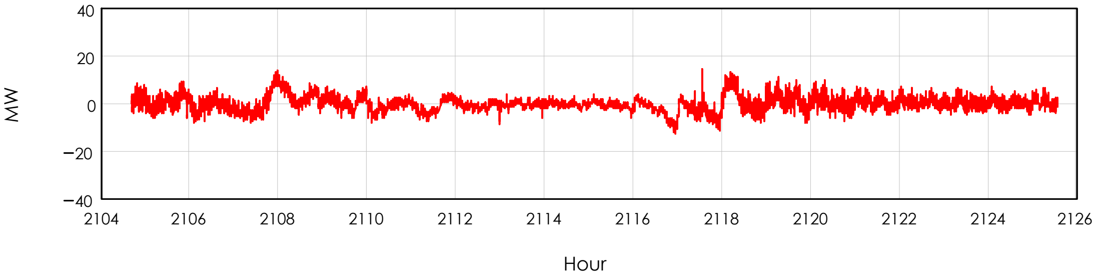




$5\,\mathrm{stdev}\,(Dev) = 17.3$

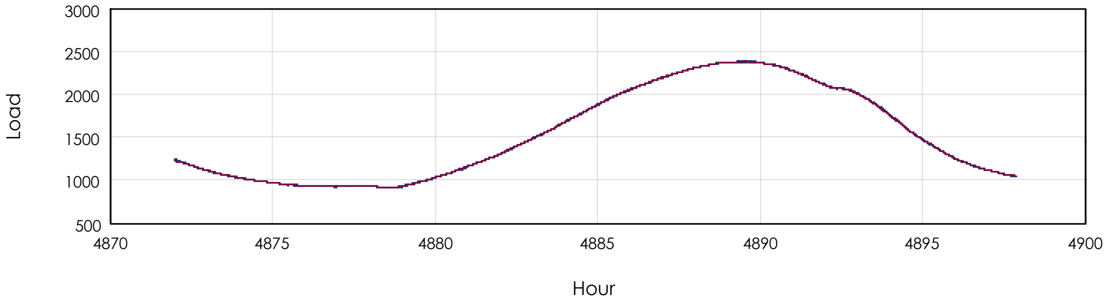
$$\frac{5\cdot\mathrm{stdev}\,(Dev)}{\max\,(L1)} = 1.35\ \%$$

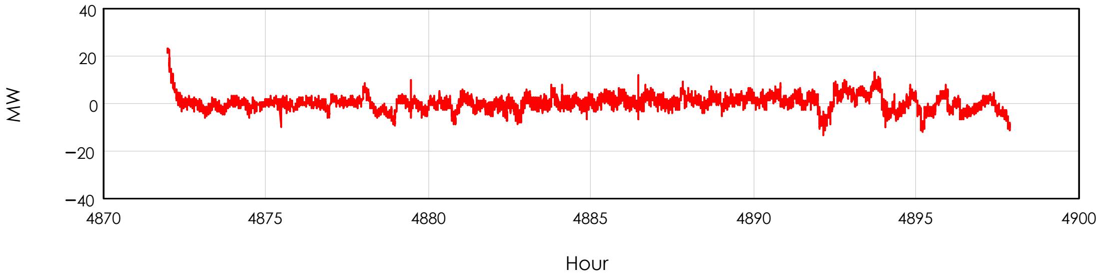




$5\,\mathrm{stdev}\,(Dev) = 16.7$

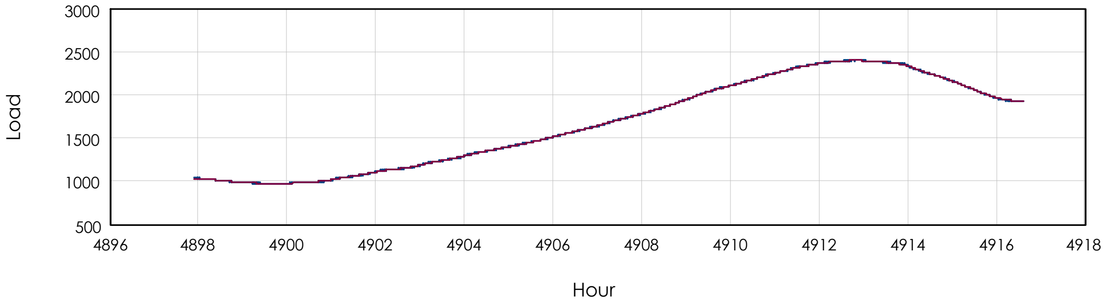
$$\frac{5\cdot\mathrm{stdev}\,(Dev)}{\max\,(L1)} = 1.3\ \%$$

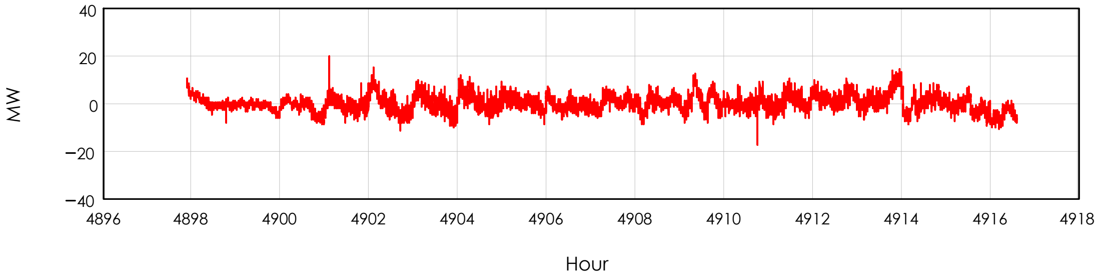




$$5\ \text{stdev}\ (\text{Dev}) = 16.6$$

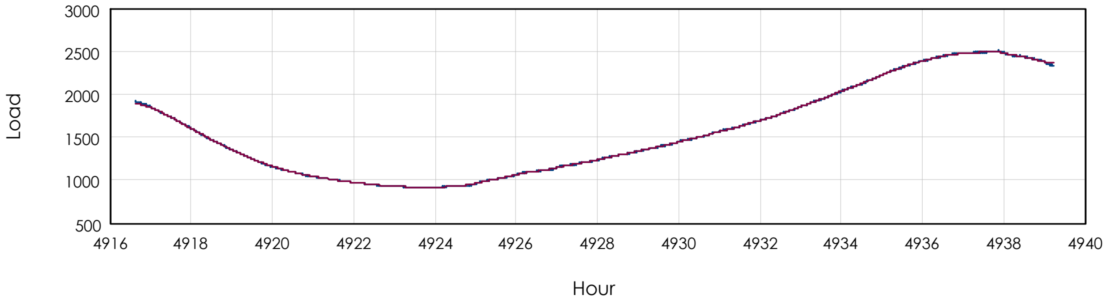
$$\frac{5 \cdot \text{stdev}\ (\text{Dev})}{\max\ (\text{L1})} = 0.7\ \%$$

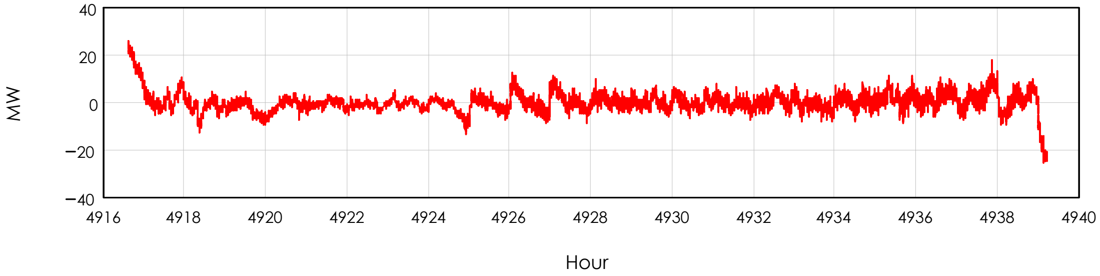




$$5\ \text{stdev}\ (\text{Dev}) = 17.8$$

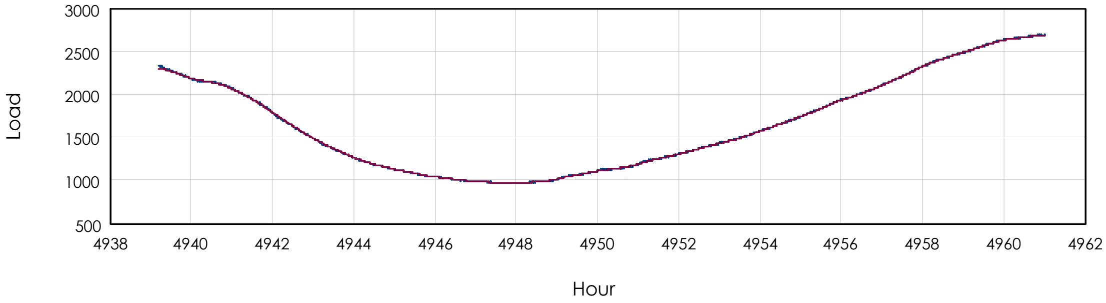
$$\frac{5 \cdot \text{stdev}\ (\text{Dev})}{\max\ (\text{L1})} = 0.74\ \%$$

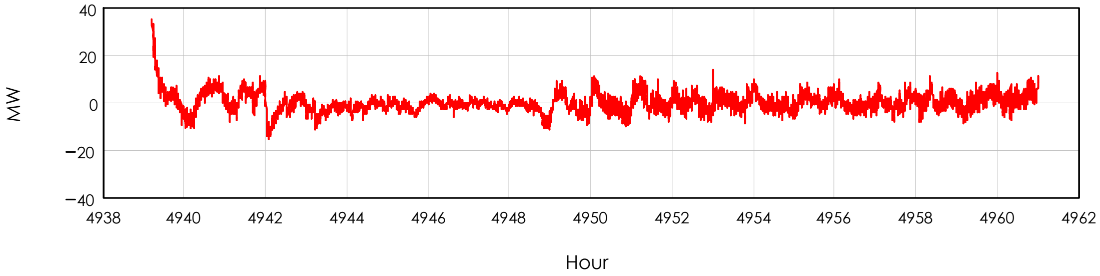




$5\ \mathrm{stdev}\ (\mathrm{Dev}) = 22.2$

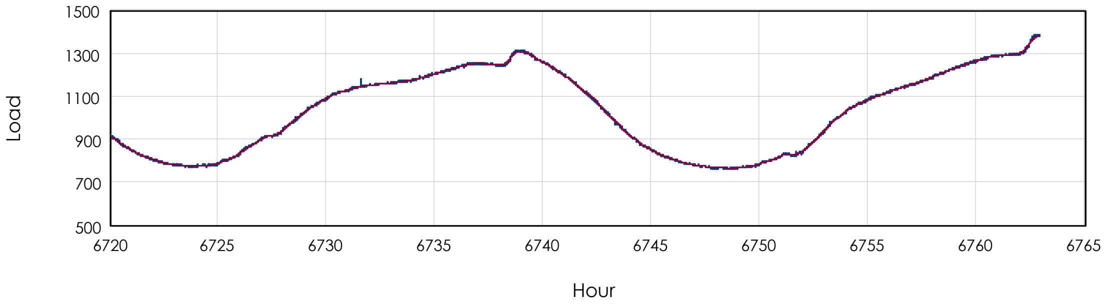
$$\frac{5 \cdot \mathrm{stdev}\ (\mathrm{Dev})}{\max\ (L1)} = 0.89\ \%$$

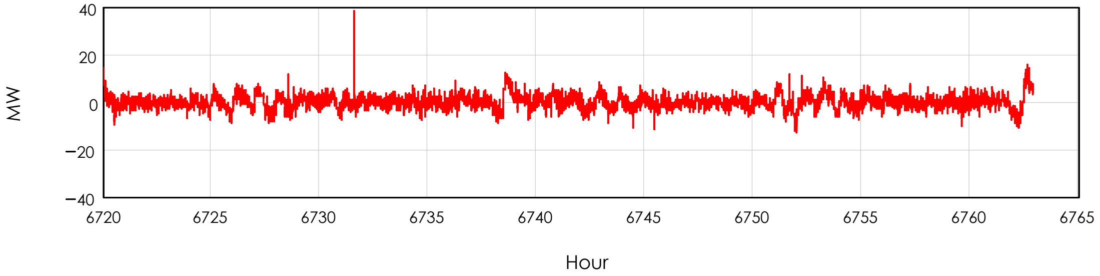




$5\ \mathrm{stdev}\ (\mathrm{Dev}) = 21.6$

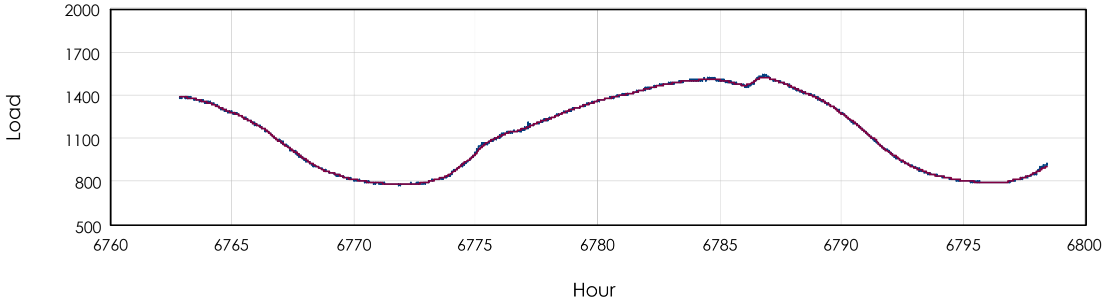
$$\frac{5 \cdot \mathrm{stdev}\ (\mathrm{Dev})}{\max\ (L1)} = 0.8\ \%$$

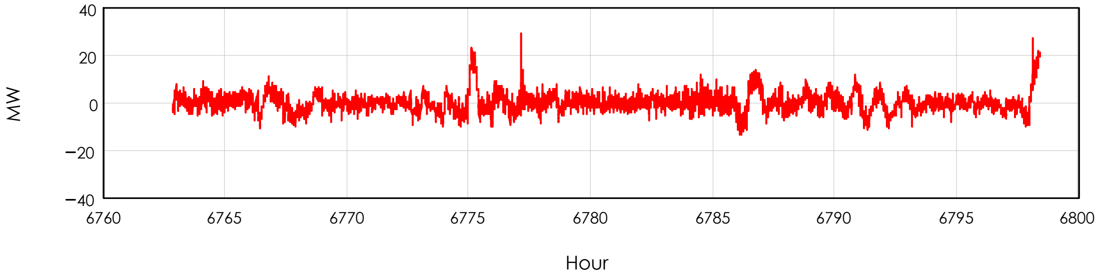




$5\,\text{stdev}\,(Dev) = 15.7$

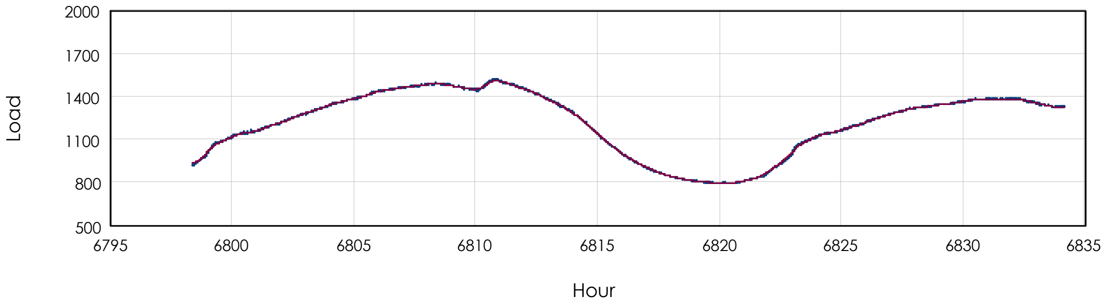
$\frac{5\cdot\text{stdev}\,(Dev)}{\max\,(L1)} = 1.13\ \%$

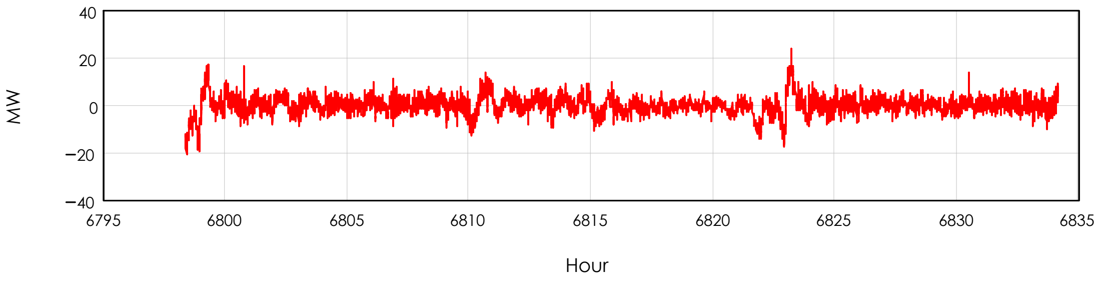




$5\,\text{stdev}\,(Dev) = 20.0$

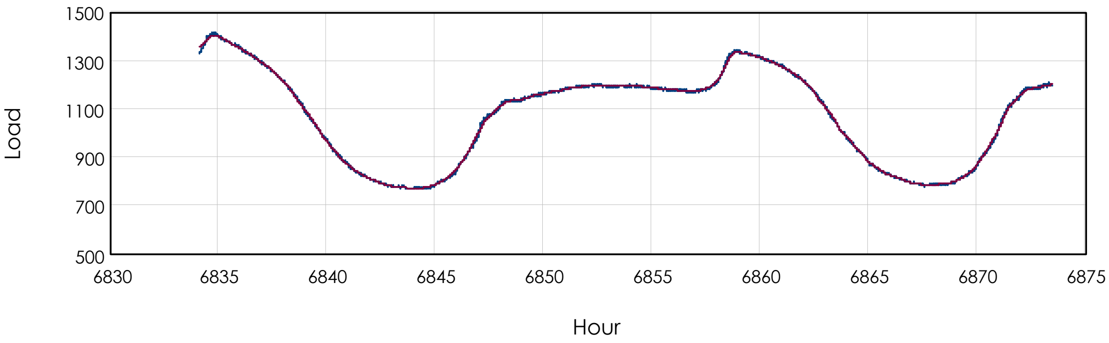
$\frac{5\cdot\text{stdev}\,(Dev)}{\max\,(L1)} = 1.3\ \%$

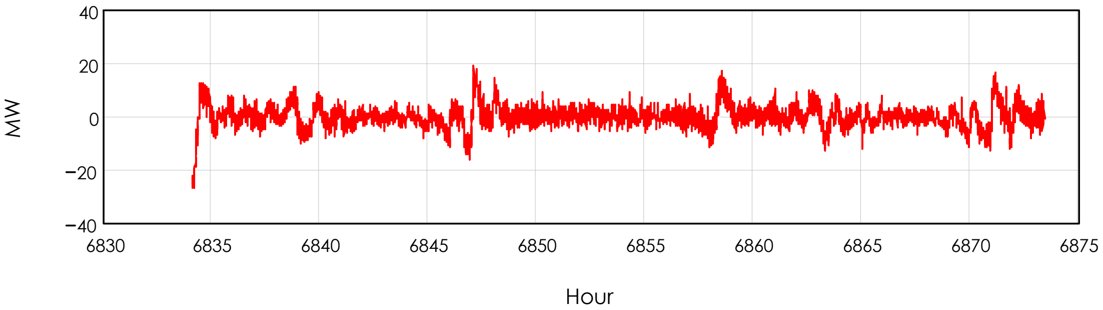




$5\ \text{stdev}\ (\text{Dev}\ ) = 20.0$

$$\frac{5 \cdot \text{stdev}\ (\text{Dev}\ )}{\max\ (\text{L1}\ )} = 1.32\ \%$$





$5\ \text{stdev}\ (\text{Dev}\ ) = 22.1$

$$\frac{5 \cdot \text{stdev}\ (\text{Dev}\ )}{\max(\text{L1}\ )} = 1.56\ \%$$

3.5 Task 5–Hourly Dispatch Simulations

The five case sets described in the previous section where analyzed using the constrained unit commitment application from AREVA T&D, e-terra Commit. The following table summarizes the integration cost results.

Table 24. Integration cost summary for all runs

Case Set	Case 1	Case 2	Case 3	Case 4
Base	4.48	7.41	5.12	3.96
Base Discounted Forecast	7.80	9.16	4.87	0.97
Base PIRP w/ Discounted Forecast	7.38	7.67	4.49	0.71
Iowa Hill Base	5.12	3.08	2.22	1.67
Iowa Hill JIT Commit	4.94	5.77	0.20	-0.12

Source: EnerNex Corporation

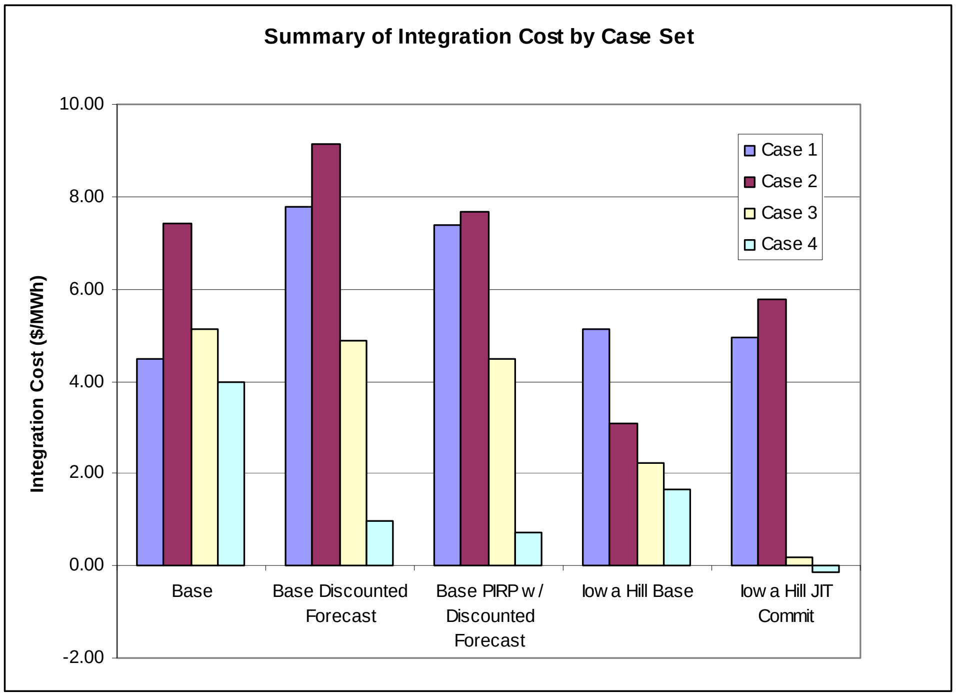


Figure 43. Integration cost summary by case set

Source: EnerNex Corporation

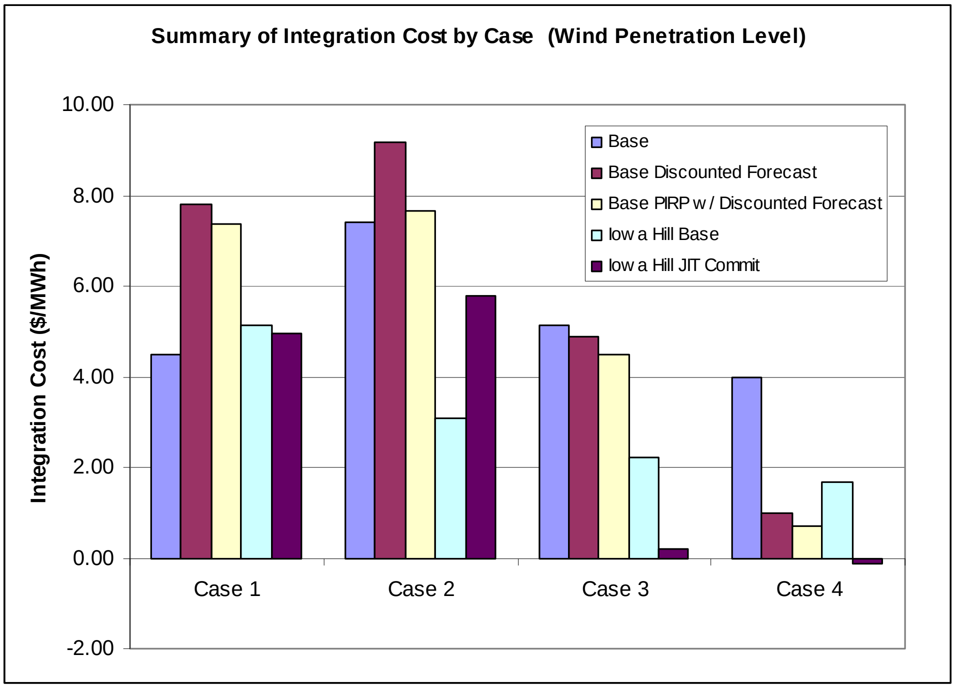


Figure 44. Integration cost summary by case (wind penetration level)

Source: EnerNex Corporation

Several generalizations can be gained from this summary. First, the discounted forecast cases that provide a hedge against lower than forecast winds also substantially increase integration costs. This is an expected result as the discounted forecast leads to less than optimum commitment of SMUD resources and higher than necessary purchases from California ISO and other power providers.

Second, given that the difference between the discounted forecast base and the PIRP discounted forecast base is the cost of carrying extra reserves for the wind rests with SMUD in the Non-PIRP, these cases directly show the cost of carrying these extra reserves.

Finally, all case sets except the Iowa Hill base show a peak in integration cost at Case 2 (Case 2 is 250 MW, all at Solano). This case represents the least diverse scenario of the four, which partially accounts for its higher costs. This, however, is not enough to account for the entire decline in costs as penetration increases. One would expect that as penetration increases–the increased cost of reserves and effects of uncertainty in the wind on optimum commitment–the overall integration cost would increase. The additional factor which accounts for this decline is the effect of the HASP sales. This will be investigated in detail later in this section.

Detailed Results for Case Sets

The following tables provide detailed results for each of the five case sets solved as part of the study.

Table 25. Base case results

Case set–Base		Reference Analysis			Simulation (“Actual”) Analysis			
Case	Wind (GWh)	Unserved (GWh)	Excess (Gwh)	Production Cost (M$)	Unserved (GWh)	Excess (GWh)	Production Cost (M$)	Integration Cost ($/MWh)
Case 1	292	38	26	455	54	21	457	4.48
Case 2	703	38	27	446	103	30	451	7.41
Case 3	1290	33	33	433	243	21	440	5.12
Case 4	2400	23	116	416	342	106	426	3.96

Source: EnerNex Corporation

Table 26. Discounted forecast base case results

Base disc. Forecast		Reference Analysis			Simulation (“Actual”) Analysis			
Case	Wind (GWh)	Unserved (GWh)	Excess (Gwh)	Production Cost (M$)	Unserved (GWh)	Excess (GWh)	Production Cost (M$)	Integration Cost ($/MWh)
Case 1	292	39	26	455	46	27	457	7.80
Case 2	703	35	27	446	64	37	453	9.16
Case 3	1290	34	33	433	77	40	439	4.87
Case 4	2400	31	116	415	111	64	418	0.97

Source: EnerNex Corporation

Table 27. PIRP base case results

Base PIRP		Reference Analysis			Simulation ("Actual") Analysis			
Case	Wind (GWh)	Unserved (GWh)	Excess (Gwh)	Production Cost (M$)	Unserved (GWh)	Excess (GWh)	Production Cost (M$)	Integration Cost ($/MWh)
Case 1	292	39	26	455	47	26	457	7.38
Case 2	703	35	27	446	82	37	452	7.67
Case 3	1290	34	33	433	91	40	438	4.49
Case 4	2400	31	116	416	109	62	417	0.71

Source: EnerNex Corporation

Table 28. Iowa Hill base case results

Iowa Hill Base		Reference Analysis			Simulation ("Actual") Analysis			
Case	Wind (GWh)	Unserved (GWh)	Excess (Gwh)	Production Cost (M$)	Unserved (GWh)	Excess (GWh)	Production Cost (M$)	Integration Cost ($/MWh)
Case 1	292	72	22	443	25	17	444	5.12
Case 2	703	64	22	434	80	15	436	3.08
Case 3	1290	60	22	421	189	11	424	2.22
Case 4	2400	55	28	402	285	30	406	1.67

Source: EnerNex Corporation

Table 29. Iowa Hill "JIT Commit" case results

Iowa Hill–1Hr Persist Commitment		Reference Analysis			Simulation ("Actual") Analysis			
Case	Wind (GWh)	Unserved (GWh)	Excess (Gwh)	Production Cost (M$)	Unserved (GWh)	Excess (GWh)	Production Cost (M$)	Integration Cost ($/MWh)
Case 1	292	72	22	443	17	17	444	4.94
Case 2	703	64	21	434	39	26	438	5.77
Case 3	1290	60	22	421	116	11	421	0.20
Case 4	2400	55	28	402	181	17	402	-0.12

Source: EnerNex Corporation

Comparison of PIRP vs. Non-PIRP Results

Two of the case sets are identical except the way in which reserves are managed. In the case of the reduced forecast base, this set had increased reserve requirements allocated based upon the wind values. The PIRP set has no additional reserve requirements placed on it. The comparison of these two cases should demonstrate the cost of the additional reserves allocated for the uncertainty in the wind. The following table summarizes this comparison.

Based on these results, it appears that the there is a very small effect on the overall performance of the system in terms of overall costs.

Table 30. Comparison of cost between PIRP and non-PIRP case

		Generation Costs	Purchase Cost	Total Cost	HASP Revenue	Net Cost
Case 1	PIRP	254	214	468	11	457
	Non PIRP	254	280	534	77	457
Case 2	PIRP	254	224	479	27	452
	Non PIRP	254	226	480	27	453
Case 3	PIRP	233	248	480	42	438
	Non PIRP	243	238	481	42	439
Case 4	PIRP	230	264	494	77	417
	Non PIRP	228	267	494	77	418

Source: EnerNex Corporation

Below is a reprise of the integration costs for these two cases. There is a more discernable difference for this metric. This is expected since the integration cost looks at small differences between the actual and reference cases that magnify the costs associated with the reserves.

Table 31. Comparison of integration cost between PIRP and non-PIRP case

Case Set	Case 1	Case 2	Case 3	Case 4
Base Discounted Forecast	7.80	9.16	4.87	0.97
Base PIRP w/ Discounted Forecast	7.38	7.67	4.49	0.71

Source: EnerNex Corporation

As seen here, the integration costs are consistently less for the non-PIRP showing the higher costs associated with carrying the higher reserve levels. In absolute terms of operating cost, however, these differences amount only to a few tenths of a percent in most cases analyzed.

There are some outstanding issues at this time concerning the handling of reserve deficits by the e-terra Commit application. This leaves some questions regarding the accuracy of these calculations. Further analysis is warranted to verify or refute these issues.

Reduction of Integration Cost with Wind Penetration

It was noted above that the integration cost drops significantly with wind penetration level. At first, this seems counterintuitive since it would seem likely that more wind would require less efficient commitment to handle the uncertainty and variability in the wind energy delivery.

One aspect of lowering the effect of higher wind penetrations is increased geographic diversity. Cases 1 and 2 are concentrated scenarios with all of the turbines in a relatively small area and are affected by essentially the same meteorology at the same time. In Cases 3 and 4, the wind plants are scattered over a much greater geographic area. This tends to diversify the wind because even though one site has low wind another might have high wind.

A unique aspect of this analysis is the real-time HASP market based on hour-ahead bids. In the strategy set up for this study, the HASP is calculated one hour ahead of the bid by subtracting the day-ahead forecast for wind from the two-hour persistence forecast. This value is offered into the HASP and accounts for significant revenue. This is the feature that drives down integration costs at higher penetration levels. The HASP operates as a near real-time outlet for excess wind generation.

The following table reviews the integration costs for the four penetration levels studied. The Base PIRP with discounted forecast was chosen because it clearly demonstrates the factors behind the lower integration costs at higher penetrations.

Table 32. Integration costs for Base PIRP case set

Case Set	Case 1	Case 2	Case 3	Case 4
Base PIRP w/ Discounted Forecast	7.38	7.67	4.49	0.71

Source: EnerNex Corporation

The following figures show the underlying operating costs and revenues for these cases in both the reference and "actual" runs. The reference run shows the decrease in generation as wind increases and is purchased at a below-average cost of $30/MWh. This particular value is not that important as the same MWh of wind is included in the "actual" case and so the values "subtract out" in the final analysis. The reference case does not include HASP sales.

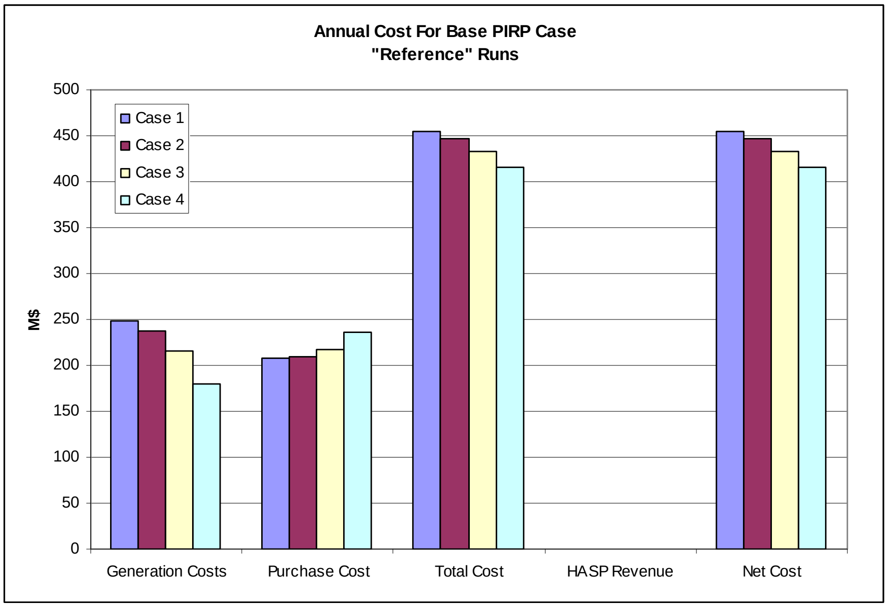


Figure 45. Annual costs for Base PIRP case set–reference run

Source: EnerNex Corporation

The actual run shows that generation costs stay about the same and purchase costs do actually go up for the cases. The result is a total cost that increases with penetration. However, when the revenues from the HASP sales are subtracted from the operating cost, the net costs decrease with penetration.

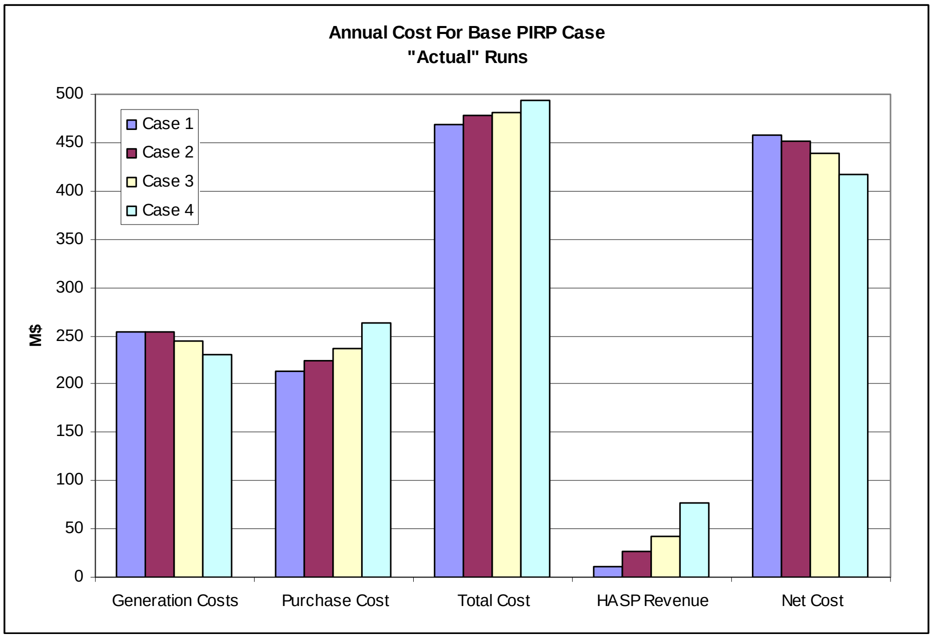


Figure 46. Annual costs for Base PIRP case set–"actual" run

Source: EnerNex Corporation

Finally, the next figure shows the difference between the actual and reference runs, emphasizing the differences in cases and clearly showing the effects of the HASP revenues in reducing the integration costs.

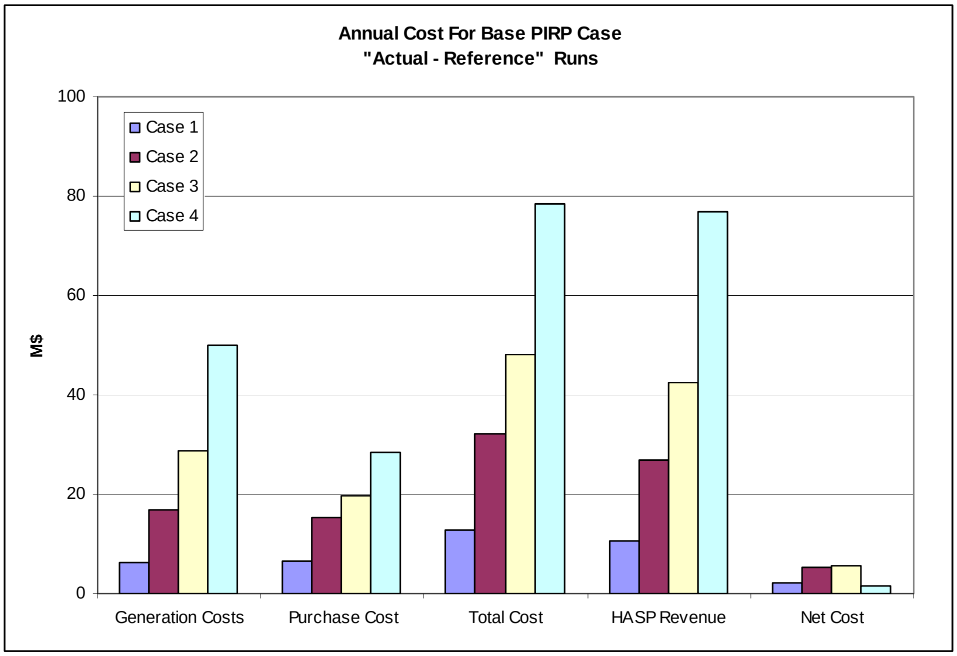


Figure 47. Annual costs for Base PIRP case set–difference

Source: EnerNex Corporation

Comparison of Discounted vs. Full Forecast Results

The effect of forecast accuracy on integration cost has been well documented in other studies, so it is no surprise that integration costs increase when the forecast is discounted heavily from the skills-based forecast. However, with the risk of not meeting energy needs if wind comes in substantially under forecast, a hedge strategy of under forecasting the wind makes sense to position the system to handle any wind outcome that may come along. The price paid is a less efficient commitment and dispatch than optimal.

Table 33. Integration costs for Base PIRP vs. Base Discounted Forecast case set

Case Set	Case 1	Case 2	Case 3	Case 4
Base	4.48	7.41	5.12	3.96
Base Discounted Forecast	7.80	9.16	4.87	0.97

Source: EnerNex Corporation

The base case with full forecast did not have full wind modified reserves in place and did not use the same HASP calculation in Cases 2 and 4. These cases are to be re-run in the near future to clarify these results. The higher cost for Cases 1 and 2 reflect the less than optimal deployment of resources in the discounted forecast case. As seen in the section on decreasing integration cost with penetration, Case 3 and 4 values for the discounted forecast are dropping due mainly to the revenue from HASP sales. A re-run of Cases 3 and 4 will provide better values for these case. However, due to the way the

HASP is calculated, the full forecast case set will always have less HASP sales compared to the discounted forecast runs. HASP is calculated as the difference between a two-hour persistence forecast and the day-ahead forecast. With the day-ahead forecast larger in the case of the full forecast case sets, the difference will be smaller, leaving the total HASP energy and revenue lower.

There is tension in both directions on integration cost for the re-run of the base cases so prediction of the change is difficult.

Effects of Iowa Hill Pumped Storage Facility

Two case sets were run with the proposed Iowa Hill 400 MW pump storage facility. These cases have different reserve requirements, as they were originally run before the finalization of the wind modified reserve regime. These cases will be redone using the appropriate reserved schemes and presented in an addendum to this report. Both non-PIRP and PIRP scenarios will be provided.

Table 34. Integration costs for Iowa Hill case sets

Case Set	Case 1	Case 2	Case 3	Case 4
Base	4.48	7.41	5.12	3.96
Iowa Hill Base	5.12	3.08	2.22	1.67
Iowa Hill JIT Commit	4.94	5.77	0.20	-0.12

Source: EnerNex Corporation

The results available here show a very substantial reduction in operating and integration costs with Iowa Hill operating. The cost savings varies with penetration and a strong correlation is not seen in the preliminary numbers above. However, savings in the range of $3/MWh to $4/MWh is possible at higher penetration levels.

3.6 Task 6–Interconnection Considerations

3.6.1 Electrical Aspects of Wind Turbine Technology

Almost all of the wind turbines deployed in large wind generation facilities in the United States during the past decade can be generally described by one of the following configurations:

- Stall-regulated (fixed-pitch) blades connected to a hub, which is coupled via a gearbox to a conventional squirrel-cage induction generator. The generator is directly connected to the line, and may have automatically switched shunt capacitors for reactive power compensation and possibly a soft-start mechanism that is bypassed after the machine has been energized. The speed range of the turbine is fixed by the torque vs. speed characteristics of the induction generator.
- A wound rotor induction generator with a mechanism for controlling the magnitude of the rotor current through adjustable external rotor circuit resistors, and pitch regulation of the turbine blades to assist in controlling speed. The speed range of the turbine is widened because of the external resistors.

- A wound rotor induction generator where the rotor circuit is coupled to the line terminals through a four-quadrant power converter. The converter provides for vector (magnitude and phase angle) control of the rotor circuit current, even under dynamic conditions, and substantially widens the operating speed range of the turbine. Turbine speed is primarily controlled by actively adjusting the pitch of the turbine blades.

While not represented in the present fleet of commercial turbines for application in the United States, another option is the variable-speed wind turbine with a full-rated power converter between the electrical generator and the grid. The first utility-scale variable-speed turbine in the United States employed this topology, and many see this configuration re-emerging for future large wind turbines. The power converter provides substantial decoupling of the electrical generator dynamics from the grid, such that the portion of the converter connected directly to the electrical system defines most of the characteristics and behavior important for power system studies.

3.6.2 Overview of Operation

A generalized wind turbine model is shown in Figure 48, and illustrates the major subsystems and control hierarchy that may influence the behavior of a single wind turbine in the time horizon of interest for large power system studies.

A wind turbine converts kinetic energy in a moving air stream to electric energy. Mechanical torque created by aerodynamic lift from the turbine blades is applied to a rotating shaft. An electrical generator on the same rotating shaft produces an opposing electromagnetic torque. In steady operation, the magnitude of the mechanical torque is equal to that of the electromagnetic torque, so the rotational speed remains constant and real power (the product of rotational speed and torque) is delivered to the grid. Since the wind speed is not constant, a variety of control mechanisms are employed to manage the conversion process and protect the mechanical and electrical equipment from conditions that would result in failure or destruction.

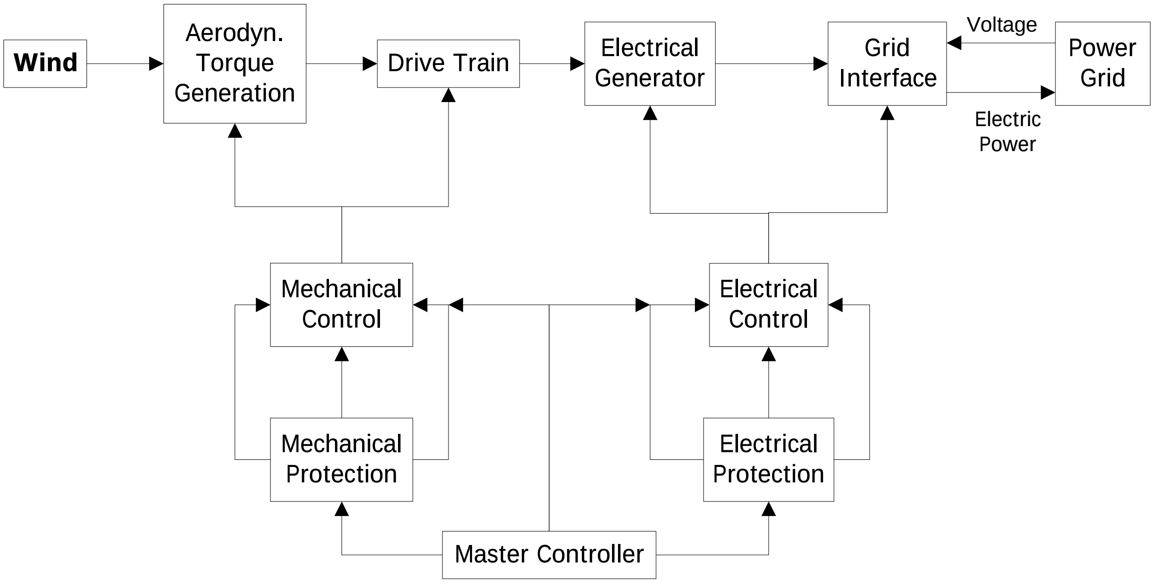

Wind
Aerodyn. Torque Generation
Drive Train
Electrical Generator
Grid Interface
Voltage
Power Grid
Electric Power
Mechanical Control
Electrical Control
Mechanical Protection
Electrical Protection
Master Controller

Figure 48. Generalized wind turbine model with control elements and hierarchy

Source: EnerNex Corporation

3.6.3 Mechanical Systems and Control

Mechanically, the turbine must be protected from rotational speeds above some value that could lead to catastrophic failure. Mechanical brakes are provided for stopping the turbine in emergency conditions, but are not used in normal operations. Controlling the power (and hence, torque) extracted from the moving air stream is the primary means for protecting the turbine from over-speed under all but emergency shutdown conditions.

In fairly steady conditions, the power extracted from the air stream by the turbine blades can be characterized by Equation 1:

$$P = \frac{1}{2} \cdot \rho \cdot \pi \cdot R^2 \cdot \upsilon^3 \cdot C_p \quad \text{Equation 1}$$

where

ρ = air density (nominally 1.22 kg/m^3)

R = radius of area swept by the turbine blades

υ = speed of moving air stream

C_p = "coefficient of performance" for the composite airfoil (rotating blades)

C_P itself is not a constant for a given airfoil, but rather is dependent on a parameter λ, called the tip-speed ratio, which is the ratio of the speed of the tip of the blade to the speed of the moving air stream.

Since wind speed and air density cannot be controlled and the radius of the blades is fixed, the performance coefficient is the only means for torque control. In some wind turbines, blades are designed so that C_P falls dramatically at high wind speeds. This method of aerodynamic torque control is known as *stall regulation*, and is limited to preventing turbine over-speed during extreme gust conditions and limiting maximum shaft power in winds at or above the rated value.

Large wind turbines employ a more sophisticated method of aerodynamic torque regulation that has benefits in addition to preventing mechanical over-speed. The performance coefficient can also be changed by adjusting the "angle of attack" of the blades, as is done on some modern propeller-driven aircraft. Figure 49 shows C_P as a function of λ for a modern wind turbine. Blade pitch adjustment allows the energy capture to be optimized over a wide range of wind speeds (even if the rotational speed of the shaft is relatively constant), while still providing for over-speed protection through large adjustments in pitch angle.

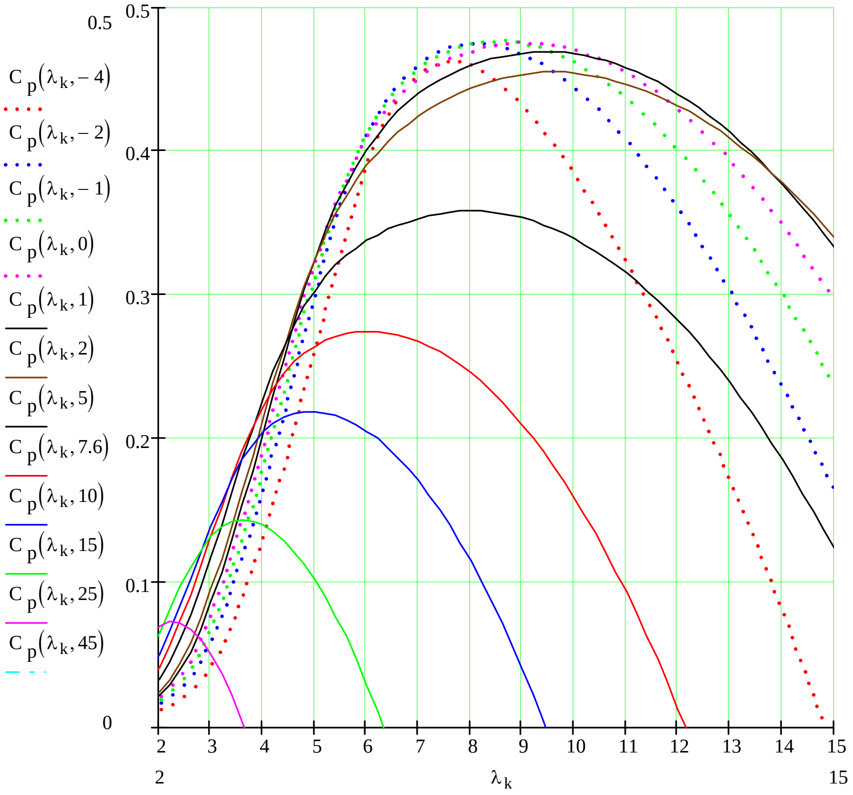


Figure 49. Coefficient of performance (C_p) for a modern wind turbine blade assembly as a function of tip-speed ratio (λ) and blade pitch (β, in degrees)

Source: EnerNex Corporation

The pitch of the turbine blades is controlled by an actuator in the hub that rotates each blade about a longitudinal axis. The inertia of the blade about this axis and the forces opposing such a rotation of the blades are not negligible. Pitching of the blades, therefore, does not happen instantaneously, with the dynamics governed by the longitudinal inertia of the blades, forces acting on the blade (which can be wind speed and pitch dependent), and the torque capability of the pitch actuator mechanism.

The characteristic shown in Figure 49 is a "quasi-static" depiction of the blade performance, in that is does not account for turbulence effects, blade vibration with respect to the average speed of rotation, or other asymmetries such as tower shadowing. It does, however, provide a much simpler means of incorporating the otherwise very complex details of the aerodynamic conversion process into models for electrical-side studies of the turbine.

The overall conversion of wind energy to electric power is normally described by a turbine "power curve", which shows turbine electrical output as a function of steady wind speed (Figure 50). Such a representation is accurate only for steady-state operation, since the inherent dynamics of the mechanical and electrical systems along with all possible control functionality is neglected.

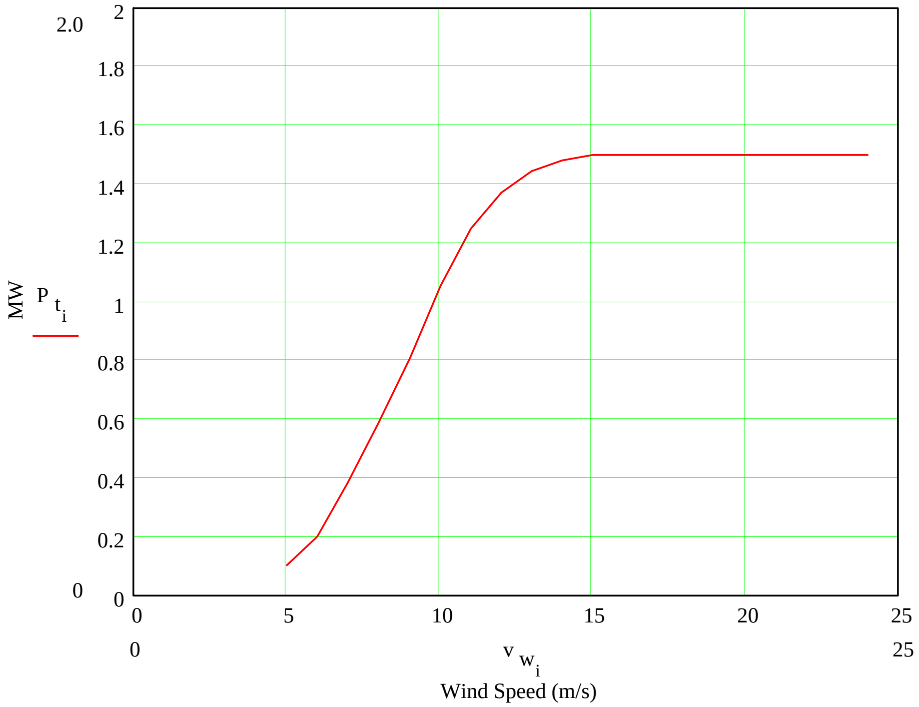


Figure 50. Power curve for a variable-speed, pitch-controlled wind turbine. Note "flatness" of output for wind speeds at or above rated value.

Source: EnerNex Corporation

Rotational speeds of large wind turbines are partly limited by maximum blade tip speed, and are relatively low for megawatt-class turbines with long blades, in the 15 to

30 rpm range. With conventional electrical generators, a gearbox is necessary to match the generator speed to the blade speed. The resulting mechanical system, then, has low-speed and high-speed sections, with a gearbox in between, as shown in Figure 51 (top). An even simpler representation is shown at the bottom of Figure 51, where the gearbox inertia is added to the inertia of the generator, and all components are referred to the high-speed shaft by the square of the gear ratio.

For megawatt-scale turbines, the mechanical inertia is relatively large, with typical inertia constants (H) of 3.0 seconds or larger (the inertia constant for the generator only will typically be about 0.5 s). The mechanical inertia is an important factor in the dynamic behavior of the turbine, because the large inertia implies relatively slow changes in mechanical speed for both normal variations in wind speed and disturbances on the grid. In addition, the various control systems in the turbine may utilize turbine speed as an input or disturbance signal, so that large inertia will then govern the response time.

With a two-mass mechanical model, there will be one oscillatory mode. With relatively flexible drive shafts in large wind turbines, the natural frequency of this primary mode of oscillation will be in the range of 1 to 2 hertz (Hz).

3.6.4 Electrical Systems and Control

Induction machines are the energy conversion devices of choice in commercial wind turbine design. In addition to their robustness and reliability, they provide a “softer” coupling between the grid and the mechanical system of the turbine. Wind turbine manufacturers have also moved beyond the basic induction generator systems with technologies for improving control and overall efficiencies. These technologies have a definite impact on the electrical and dynamic performance of wind turbines, even to the extent of masking or overriding the dynamic characteristics that would normally be associated with rotating machinery. The four major types of generator technologies used in today’s commercial wind turbines are discussed in the following sections.

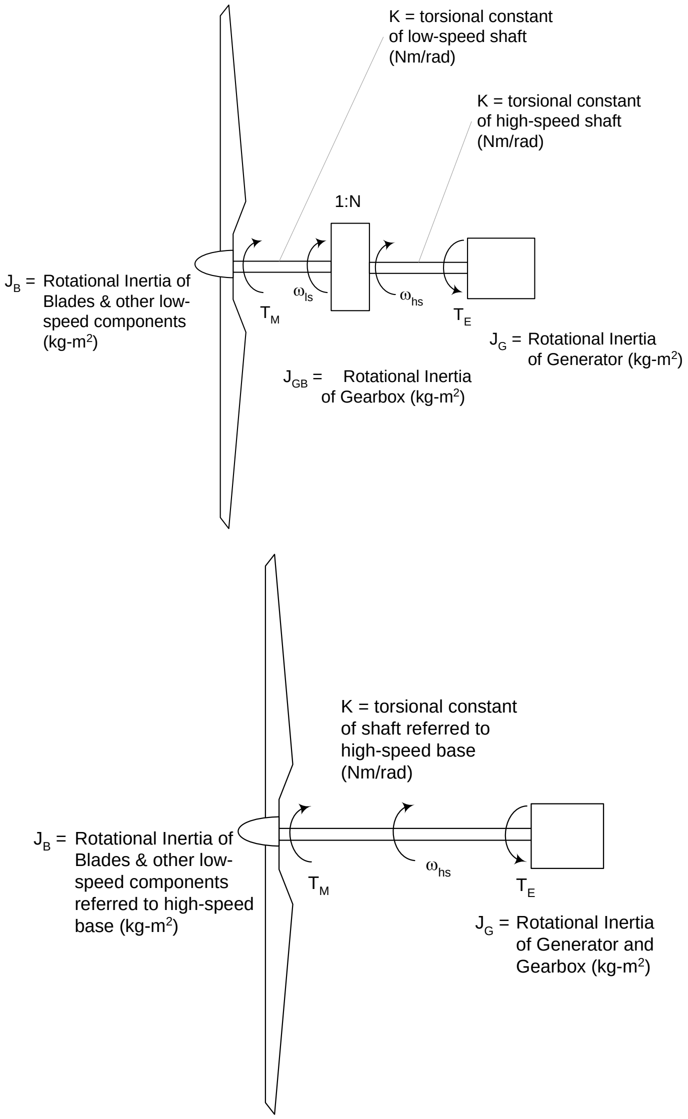

K = torsional constant of low-speed shaft (Nm/rad)
K = torsional constant of high-speed shaft (Nm/rad)
1:N
J_B = Rotational Inertia of Blades & other low-speed components (kg-m^2)
ω_{ls}
ω_{hs}
T_M
T_E
J_G = Rotational Inertia of Generator (kg-m^2)
J_{GB} = Rotational Inertia of Gearbox (kg-m^2)
K = torsional constant of shaft referred to high-speed base (Nm/rad)
J_B = Rotational Inertia of Blades & other low-speed components referred to high-speed base (kg-m^2)
ω_{hs}
T_M
T_E
J_G = Rotational Inertia of Generator and Gearbox (kg-m^2)

Figure 51. Simplified model of wind turbine mechanical system. Two mass model with gearbox (top) and model with equivalent gearbox inertia and reference of all components to high-speed shaft (bottom).

Source: EnerNex Corporation

3.6.5 Direct-Connected Induction Generators

Wind turbines with squirrel-cage induction generators connected directly to the line are the simplest electrically. While for purposes of aerodynamic efficiency they operate at nearly constant speed, the slight variation of speed with torque (and power) can significantly reduce mechanical torque transients associated with gusts of wind and grid-side disturbances.

The speed range of the turbine is dictated by the torque vs. speed characteristic of the induction generator (Figure 52). For large generators in today's commercial turbines, slip at rated torque is less than 1 percent, which results in very little speed variation over the operating range of the turbine. For a given wind speed, the operating speed of the turbine under steady conditions is a nearly linear function of torque, as illustrated by the torque vs. speed characteristic of Figure 52. For sudden changes in wind speed, the mechanical inertia of the drive train will limit the rate of change in electrical output.

Because the induction generator derives its magnetic excitation from the grid, the response of the turbine during a grid disturbance will be influenced by the extent to which the excitation is disrupted.

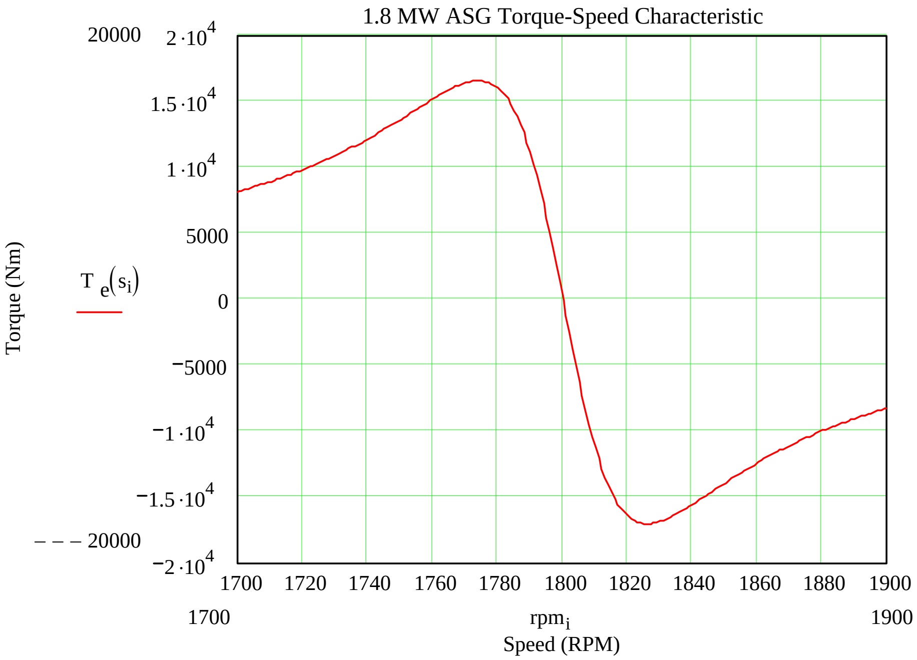


Figure 52. Torque vs. Speed characteristic for an induction machine used in a commercial wind turbine

Source: EnerNex Corporation

3.6.6 Wound-Rotor Induction Generator with Scalar Control of Rotor Current

In a squirrel-cage induction generator, the rotor "circuits" are fictitious and not accessible external to the machine, and the induced currents responsible for torque generation are strictly a function of the slip speed. The turbine shown in Figure 53 utilizes a wound-rotor induction machine, where each of the three discrete rotor winding assemblies is electrically accessible via slip rings on the machine shaft. This provides for modification of the rotor circuit quantities and manipulation of the rotor currents, and therefore the electromagnetic torque production. The Vestas turbines for domestic application (e.g. V47 and V80) utilize a patented system for controlling the magnitude of the rotor currents in the induction generator over the operating speed range of the turbine. The system (Vestas Rotor Current Controller or VRCC) consists of an external resistor network and a power electronics module that modulates the voltage across the resistors to maintain a commanded rotor current magnitude. The operation of the VRCC is quite fast, such that it is capable of holding the turbine output power constant for even gusting winds above rated wind speed, and significantly influences the dynamic response of the turbine to disturbances on the grid.

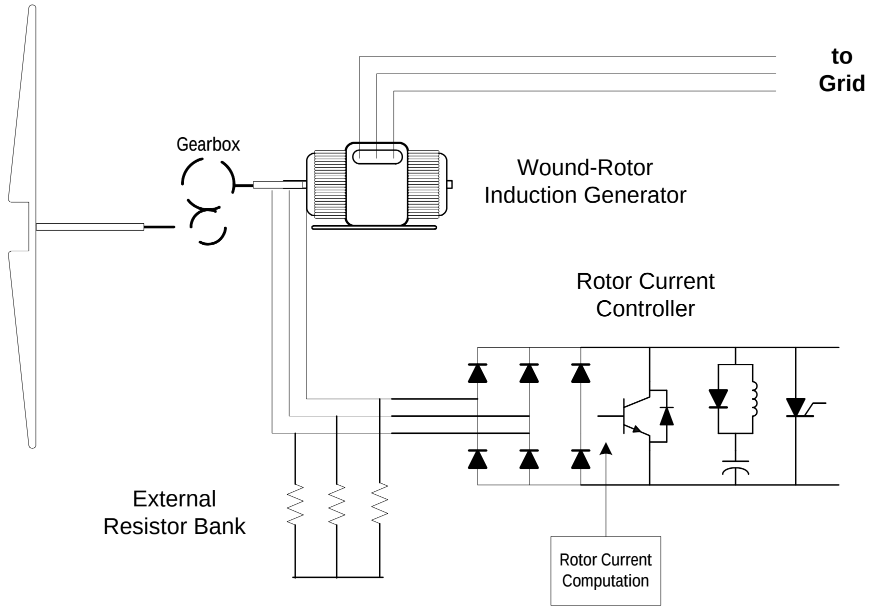


Figure 53. Configuration of a Vestas turbine for domestic application. Diagram illustrates major control blocks and Vestas Rotor Current Controller.

Source: EnerNex Corporation

The 750 kilowatt (kW) and 1.5 MW turbines (and the 3.6 MW prototype for offshore applications) from GE Wind Energy Systems employ an even more sophisticated rotor current control scheme with a wound-rotor induction generator (Figure 54). Here, the rotor circuits are supplied by a four-quadrant power converter (capable of real and reactive power flow in either direction) that exerts near-instantaneous control (e.g. magnitude and phase) over the rotor circuit currents. This “vector” control of the rotor currents provides for fast dynamic adjustment of electromagnetic torque in the machine. In addition, the reactive power at the stator terminals of the machine can also be controlled via the power converter.

Field-oriented or vector control of induction machines is a well-known technique used in high-performance industrial drive systems, and its application to wind turbines brings similar advantages. In an earlier version of this turbine, the torque command (and therefore the magnitude of the rotor current component responsible for torque production) was linked to the speed of the machine via a “look-up” table. The field-orientation algorithm effectively creates an algebraic relationship between rotor current and torque, and removes the dynamics normally associated with an induction machine. The response of the power converter and control is fast enough to maintain proper alignment of the torque-producing component of the rotor current with the rotor flux so that the machine remains under relative control even during significant grid disturbances.

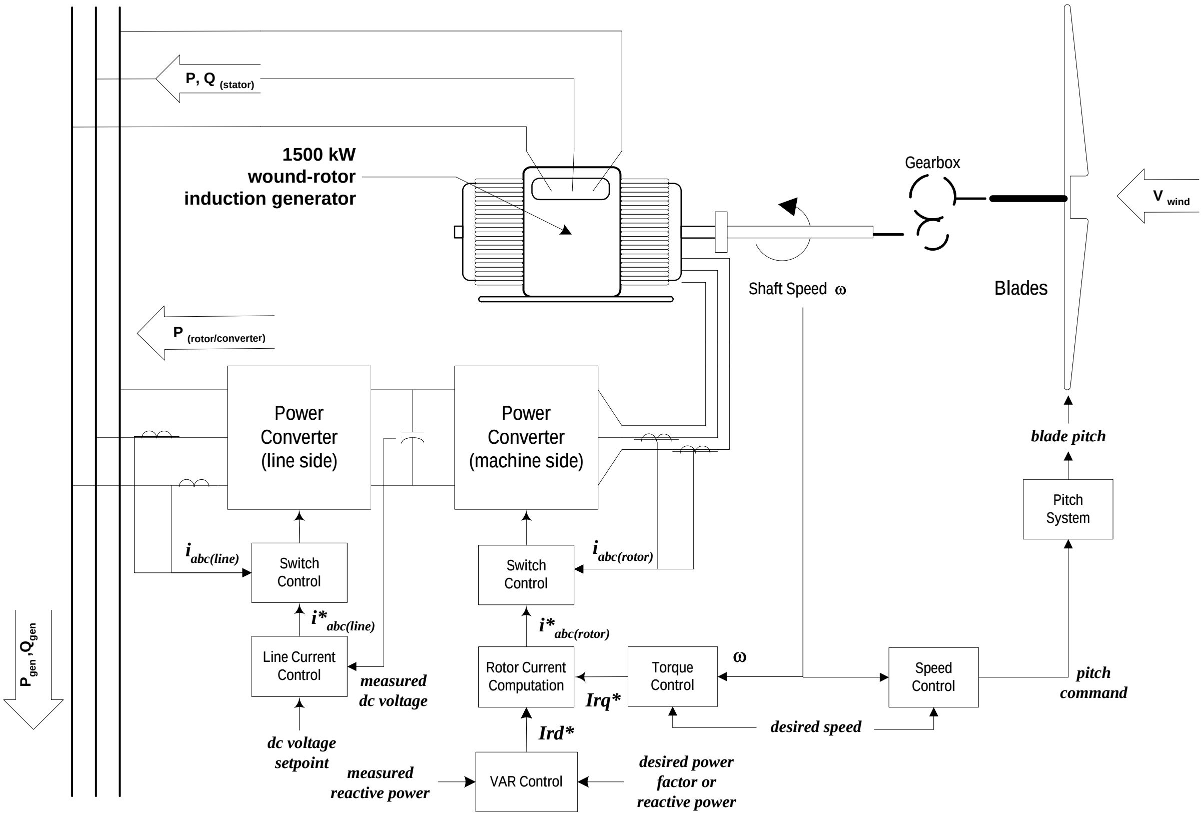

P, Q (stator)
1500 kW wound-rotor induction generator
Gearbox
V wind
Shaft Speed ω
Blades
P (rotor/converter)
Power Converter (line side)
Power Converter (machine side)
blade pitch
Pitch System
i abc(line)
Switch Control
Switch Control
i abc(rotor)
i* abc(line)
i* abc(rotor)
P gen, Q gen
Line Current Control
measured dc voltage
Rotor Current Computation
Torque Control
ω
Speed Control
pitch command
Irq*
desired speed
Ird*
dc voltage setpoint
measured reactive power
VAR Control
desired power factor or reactive power

Figure 54. Configuration of GE with four-quadrant power converter supplying rotor circuit of a wound-rotor induction generator. Control blocks for torque control also shown.

Source: EnerNex Corporation

Static Interface

The Kenetech 33 MVS, introduced commercially in the early 1990s, was the first utility-scale variable-speed wind turbine in the United States. The turbine employed a squirrel-cage induction generator with the stator winding supplied by a four-quadrant power converter (Figure 55). Because all of the power from the turbine is processed by the static power converter, the dynamics of the induction generator are effectively isolated from the power grid.

A modern static power converter utilizes power semiconductor devices (i.e. switches) that are capable of both controlled turn-on as well as turn-off. Further, the device characteristics enable switch transitions to occur very rapidly relative to a single cycle of 60 Hz voltage–nominal switching frequencies of a couple to several kHz are typical. This rapid switching speed, in combination with very powerful and inexpensive digital control, provides several advantages for distributed generation interface applications:

- Low waveform distortion with little passive filtering.
- High-performance regulating capability.
- High conversion efficiency.

- Fast response to abnormal conditions, including disturbances, such as short-circuits on the power system.
- Capability for reactive power control.

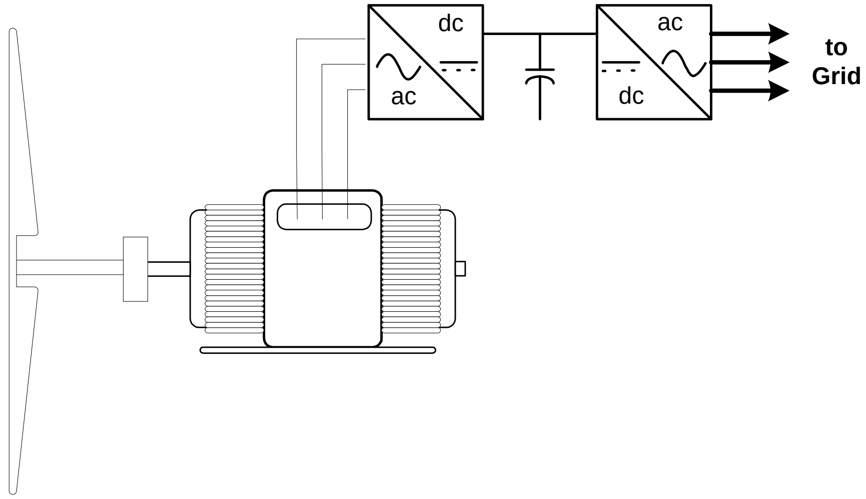


Figure 55. Variable-speed wind turbine with static power converter grid interface

Source: EnerNex Corporation

Because the effective switching speed of the power semiconductor switches is quite fast relative to the 60 Hz power system frequency, it is possible to synthesize voltage and current waveforms with very little lower-order harmonic distortion. Most modern converters easily meet limits on these harmonics found in the IEEE 519 standard.

Figure 56 depicts a simplified control schematic for a static power converter in grid-parallel operation. Since an individual wind turbine is likely small in rating relative to the short-circuit capability of the system to which it is connected, the voltage magnitude at this point will only be slightly influenced by the operation of the turbine. The control scheme, therefore, is designed to directly regulate the injection of currents into this “stiff” voltage source.

The alternating current (AC) line voltages, direct current (DC) link voltage, and two of the three AC line currents–for a three-wire connection–are measured and provided to the main controller. The AC voltage and line currents are measured at a high resolution relative to 60 Hz, so that the controller is working with instantaneous values. By comparing the measured DC voltage to the desired value, the controller determines if the real power delivered to the AC system should be increased, decreased, or held at the present value. Such a simple regulation scheme works because there is no electric energy storage in the converter (except for that in the DC filter capacitor), so the energy flowing into the DC side of the converter must be matched at all times to that injected into the AC line. If these quantities do not match, the DC link voltage will either rise or fall, depending on the algebraic sign of the mismatch.

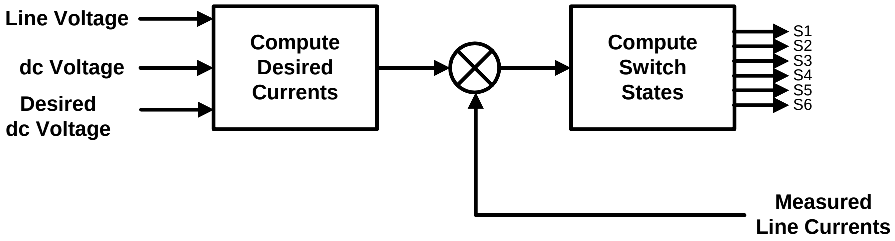


Figure 56. Simple output current control stage for a static power converter in a grid-tied DG application

Source: EnerNex Corporation

The error in the DC voltage is fed into a PI (proportional-integral) regulator to generate a value representing the desired rms magnitude of the AC line currents. Another section of the control is processing the instantaneous value of the AC line voltage to serve as a reference or "template" for the currents to be produced by the converter. The desired instantaneous value of the line current is computed by multiplying the desired rms current magnitude by the present value from the template waveform. In the next stage of the control (often times called the "modulator" section) the desired instantaneous value of line current is compared to the measure value (in each phase). The modulator then determines the desired state of the six switches in the matrix, based on the instantaneous current error in each phase of the line currents. The states are transmitted to the IGBT gate drivers, which then implement the state of each IGBT in the matrix as commanded by the controller. The process is then repeated at the next digital sampling interval of the overall control.

The process is repeated thousands of times per single cycle of 60 Hz voltage. By using the line voltage as a template for the shape of the currents to be synthesized, synchronism is assured. Additionally, if there is no intentional phase shift introduced in the control calculations, the currents will be almost precisely–save for small delays introduced by the control itself–be in phase with the line voltages, for unity power factor operation.

Figure 57 depicts the output of a current-regulation scheme that might be employed in a grid interface converter in a wind turbine. Here, the modulator will only change the state of the switches if the absolute value of the difference between the desired and actual line currents exceeds a certain value. The small errors that are continually corrected by the action of the converter control are clearly visible. Because of the high switching speed, however, the distortion of the current waveform is very low, well within IEEE 519 limits.

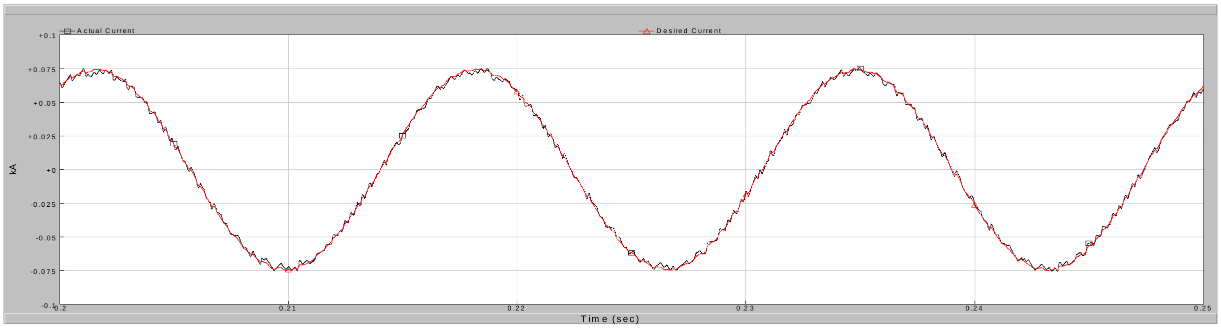


Figure 57. Static power converter output current showing reference (desired) current and actual current

Source: EnerNex Corporation

By modifying the control scheme just described to incorporate a commanded "shift" in the reference or template waveforms, reactive power flow to or from the line may also be controlled. Since the net energy flow from the reactive currents is zero (apart from very small conductive and switching losses), the DC voltage will be unaffected. Reactive power may be adjusted independently of real power flow up to the thermal limits of the switches and passive components in the converter. Reactive power generation with zero real power is also possible.

The significance of the previous discussion from the modeling perspective is that, unlike rotating machinery whose behavior is bound by fairly well-known physical principles, the response of the wind turbine static power converter equipment to events on the power system is almost entirely dictated by the embedded control algorithms. How a static power converter contributes to short-circuits, for example, cannot be deduced from the topology, or values of passive elements such as tie inductors or DC link capacitors.

Grid Interface

Commercial wind turbines use low-voltage generators (<1000 V), and connect to the medium voltage public distribution feeder or wind plant collector system through a three-phase transformer. The transformer connection is usually wye on the low-voltage side to serve turbine loads. The medium-voltage side may be either wye or delta. The transformer may be supplied by the turbine vendor, and in some cases can be located "up tower"–in the nacelle of the turbine to reduce cabling losses. Pad-mount transformers near the base of the turbine tower are also common.

All commercial wind turbines have either power factor correction or some type of power factor control. Direct-connected induction generators and those with scalar rotor current control use staged/switched shunt capacitors to correct power factor across the operational range of the turbine.

Advanced machines are capable of power factor control via the advanced rotor power converter. The converter itself may have a small L-C network on its terminals for filtering noise resulting from the fast operation of the semiconductor switches.

Protection Systems

Commercial wind turbines incorporate sophisticated systems for protection of electrical and mechanical components. These turbine-based systems respond to local conditions, detecting grid or mechanical anomalies that indicate system trouble or potentially damaging conditions for the turbine. Some are computer-based, as with those associated with the high-performance static power converter, or run as algorithms in the master turbine controller, and therefore can respond almost instantaneously to mechanical speed, vibration, voltages, or currents outside of defined tolerances.

In addition, conventional multi-function relays for electric machine protection are also provided to detect a wide variety of grid disturbances and abnormal conditions within the machine.

Wind Plant Design and Configuration

Wind turbines are just one component of bulk wind plants. With individual turbine sizes now exceeding 1 MW, nameplate ratings for single wind plants of many tens to hundreds of MW are common. The geographic extent of the wind plant must be large enough to not only accommodate dozens to a hundred or more turbines, but also allow optimal spacing and utilization of local terrain features that will maximize energy production. The infrastructure for connecting a large number of widely distributed turbines to a single point of interconnection with the transmission system has important influence over the electrical characteristics of the wind plant.

The installed and proposed utility-scale wind plants in the United States have some common design characteristics that offer potential simplifications for constructing aggregated models for transmission system studies. These commonalities stem from practicalities and optimizations regarding the local wind regime, micro-siting of individual turbines, electric system design, and operations and maintenance economies. The result is that, from the power system modeling perspective, large wind plants have the following features in common:

- **A single turbine type**–Since wind turbines are complex machines that require preventative, predictive, and on-demand maintenance to achieve the highest availability, it is better from a maintenance and operations perspective to utilize the same turbine throughout the wind plant and have a maintenance and operations staff that specializes in all aspects of this single turbine design.
- **Medium voltage collector systems and interconnect equipment**–The electrical infrastructure that “collects” power generated by each turbine in the plant and delivers it to the transmission system utilizes standard overhead and underground medium voltage (15 to 35 kV) equipment and design practices. Some variations from standard utility practices for medium voltage design are necessary; however, the operation of wind turbines varies significantly from the distributed end-use loads for which the utility practice is optimized. For example, voltage regulation and protection schemes must be modified to account for generation, rather than load, distributed along the collector lines. The

collector lines are an integral part of the wind plant, i.e. they are not utilized to serve non-wind plant load or other electric utility customers.

- **Reactive compensation**–Maintaining voltages within tolerances at individual turbines within a wind plant while at the same time meeting power factor or voltage regulation requirements at the point of interconnection with the transmission system requires careful management of reactive power. Typical locations for reactive power compensation within a wind plant are (1) at each individual turbine, dependent on the reactive power requirements and characteristics of the rotating machinery in the turbine; (2) at the interconnect substation in the form of switched shunt capacitor banks; or (3) at locations along the medium voltage collector lines depending on the layout of the plant. Some plants have the ability to dynamically control reactive power from each turbine, which offers the possibility of reactive power management for transmission system considerations to be accomplished by the turbines themselves. Terminal voltages at individual turbines, however, may be a constraint on the amount of reactive power that can be delivered to the interconnect substation during periods of high wind generation. In addition, when reactive power is required at the point of interconnection to the transmission network to support voltage, substantial reactive power may be "lost" in the medium voltage collector system between individual wind turbines and the interconnect substation.
- **SCADA and Plant Control**–Large wind plants typically have fairly extensive means for remote operation of individual turbines and collection of high-resolution operating data. Interfaces to power system operations centers are also being implemented, allowing automated implementation of control area operator commands during certain system conditions–e.g. automatic curtailment.

The most important influence of the wind plant infrastructure on the interconnection bus bar characteristics of the wind plant is on the net reactive power capability of the wind plant. Voltage profiles along the collector lines are an internal issue. For purposes of characterizing the plant for transmission studies, the static, dynamic, and load-dependent effects of the collector system on the net reactive power at the interconnection substation must be characterized. Figure 58 illustrates this influence with an example from an operating wind plant. Wind plant generation and net reactive power requirements are shown as functions of wind speed. In the figure, the net reactive power is entirely a function of reactive losses in the lengthy overhead collector lines, since the turbines are assumed to be operating at unity power factor. The stepped line shows how staged shunt capacitor banks on the collector lines might be deployed to account for this load-dependent reactive loss. Not shown on the diagram is how such a scheme would contribute to the dynamic nature of the plant. As wind speed–and power output–varies, so will the net reactive requirements. Details of the capacitor switching scheme are critical here, since there will be time delays and hysteresis associated with the capacitor bank controls. These parameters must be selected with some knowledge of the time variation of wind generation on the collector line to prevent unnecessary capacitor switching operations and potentially associated voltage flicker.

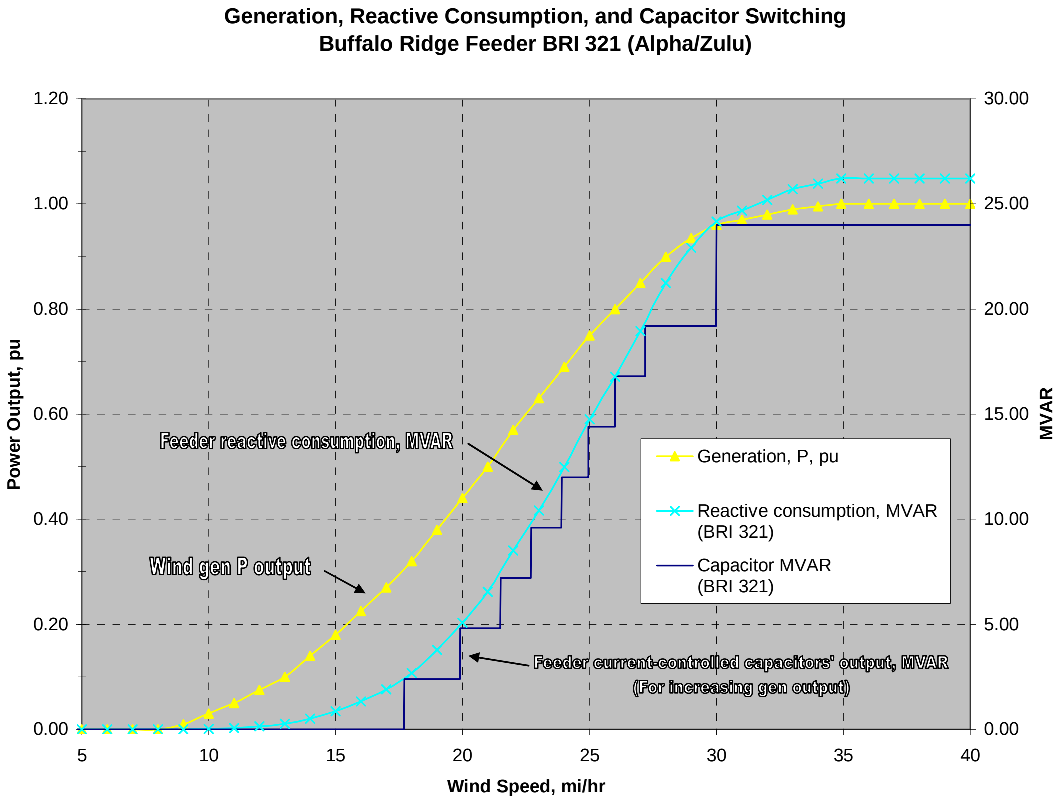


Figure 58. Illustration of the impact of collector line reactive losses on the net reactive power capability of a large wind plant

Source: EnerNex Corporation

Wind Generation Technology and Application Trends

The turbine types described previously have served the United States wind industry from the beginning of the explosive growth in the mid-1990s. Newer, bigger turbine models have been introduced along the way, but the technological improvements and modifications in the new commercial introductions have not changed the basic electrical behavior of the turbines.

Reducing the cost of energy is still the primary driver for ongoing developments in wind turbine technology. Wind generation is currently cost competitive with natural gas-fired generation due to recent and significant increases in natural gas prices. While the cost of wind energy has actually increased during the past few years due to rising steel prices and currency exchange issues, further reductions in cost are still being projected due to incremental improvements in technology. Many of these increments can be found in the low wind speed turbine research program at NREL. The desired outcome of this significant research effort is wind turbine technology capable of producing competitively-priced energy in sites with lower average annual wind speeds. These sites tend to be much closer to major electric load centers, which eases the transmission issues faced by wind plants in more favorable but remote locations.

Technological advances from this research will also contribute to further cost reductions from plants in higher wind speed regimes. NREL projects and cost targets are shown in Figure 59.

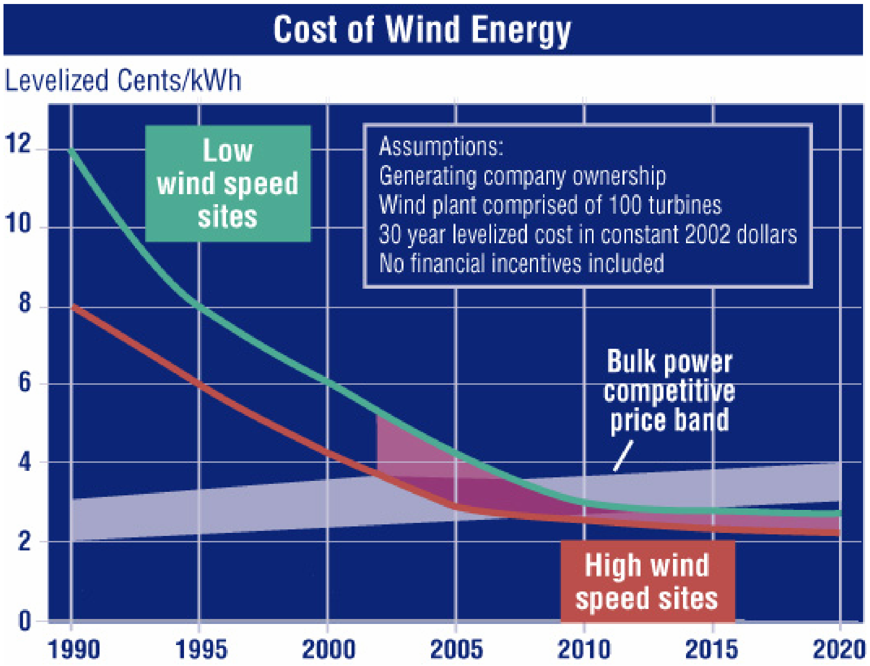


Figure 59. Projected wind energy costs with low wind-speed turbine technology

Source: NREL National Wind Technology Center

Experiences from large wind projects are also influencing wind turbine developments, and are expected to have even more impact going forward. Wind turbine vendors now recognize that some features and enhancements to the electrical performance of their products will be demanded by customers and they are critical of further expanding the overall market potential for wind generation in the United States.

Wind plant design is undergoing some evolution. Plant operators and project developers are gaining important experience from the first generations of large wind plants developed since the mid-1990s. Awareness is growing of the importance of the wind plant area between the turbines and the interconnection point to the transmission network to plant availability, turbine performance, and successful operation with the grid.

Finally, with wind generation becoming a visible fraction of the generating assets in some control areas, transmission service providers are beginning a push for more stringent wind plant performance requirements and interconnection standards.

These influences will have a positive impact on the characteristics of wind generation facilities as viewed from the transmission network during the years to come. This section describes technological changes that will lead to new wind plant features and capabilities over the coming years that will affect electrical performance and integration with the grid.

3.6.7 Wind Turbine Technology Trends

The value of variable speed technology for large wind turbines has been proven in the marketplace over the past decade, and will be the predominate technology going forward. Variable speed operation has benefits in terms of managing mechanical loads on the turbine blades, drive train, and structure. The grid-side benefits are also significant, and include dynamic reactive power control, increased dynamic control over electric power generation, and opportunities for further enhancement of grid-integration features of the turbine.

Electrical Topology

At present, the doubly-fed induction machine topology is favored both in the United States and globally. As the size of individual turbines continues to grow, there is an emerging consensus that future turbines will likely employ machines other than induction generators, possibly advanced synchronous or permanent magnet designs. For variable speed operations, these new machines will require all of the electrical output to flow through some type of power converter. This converter would almost completely define how the turbine “looks” to the power system, offering some new opportunities for improving interconnection and integration.

Electrical Robustness

Wind turbine vendors are now well aware of the need to improve turbine electric robustness, especially in terms of the ability to ride-through faults on the transmission system. Enhanced low-voltage ride through is already an option for several commercial turbines, and will likely be a standard feature in the coming few years. Farther down the road it is expected that wind turbines will be no more sensitive in terms of tripping for transmission system faults than conventional generators, and will provide flexibility with respect to “programming” their shutdown modes for grid events.

Since it first emerged as an important issue for the electric power and wind generation industries just a few years ago, the performance of wind turbines during network disturbances and their ability to ride-through low voltage events been the subject of extensive discussion and debate.

The American Wind Energy Association (AWEA) seized the initiative as part of the FERC Order 2003a process by convening a diverse group of industry stakeholders to build consensus on what ride-through standards for wind turbines was achievable commercially and would satisfy the needs of the transmission operators. The E.on Netz specification (Figure 60) was adopted as the starting point.

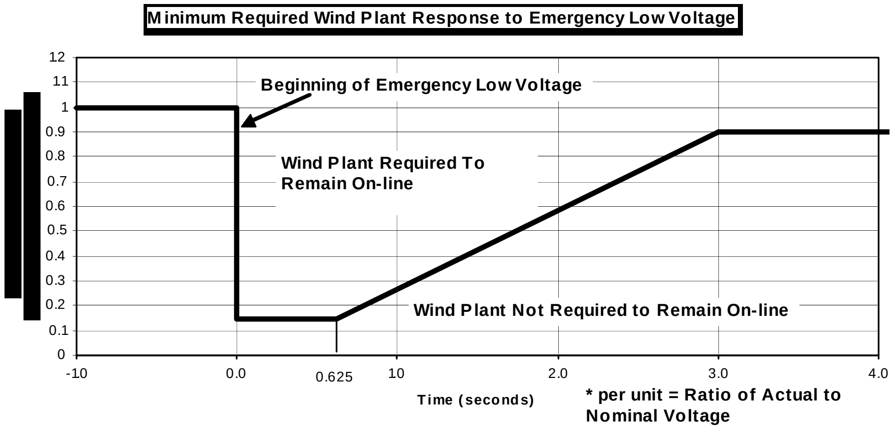


Figure 60. Adaptation of E.ON Netz Low Voltage Ride Through requirement for wind turbines, as proposed by AWEA for Appendix G of FERC Order 2003a

Source: EnerNex Corporation

A couple of points should be made here. First, the E.ON specification was developed in consideration of the technical configuration of wind turbines in Germany, where much of the current installed capacity is actually connected to public distribution networks. E.ON is a grid operator, with purview over the transmission network. This contrasts with the situation under discussion in the United States, where most of the installed capacity is connected at transmission voltages. Further, the FERC process itself considered only transmission-connected facilities. Wind turbine interconnection to public distribution feeders falls under the auspices of those standards and requirements for distributed generation (such as IEEE 1547), which is an entirely different matter.

In parallel with the AWEA initiative, many utility organizations were working to develop their own standards for Low Voltage Ride Through (LVRT). There was a fair amount of information sharing between these groups and even with AWEA, but the resulting draft standards still exhibited marked differences.

NERC/AWEA Discussions on Order 661

The North American Electric Reliability Council (NERC) was directed to convene a task force to evaluate the adequacy of existing NERC standards in their application to wind generation. The task force convened in early 2005. The NERC reliability footprint and member regions are shown in Figure 61.

NERC's goal is to become certified and begin operation as the Electric Reliability Authority (ERO) in the United States and Canada, consistent with the Energy Policy Act of 2005 and the rules and requirements of the Federal Energy Regulatory Commission (FERC) and provincial regulators. FERC issued a notice of proposed rulemaking to implement the legislation on September 1, 2005. That rulemaking will establish the requirements NERC must meet to become the ERO. The legislation requires FERC to finalize its rulemaking within 180 days of enactment (by February 4, 2006). NERC plans to submit an application to become the ERO, and expects the certification process to be completed as soon as August 2006. These efforts will result in the formation of an independent, international ERO that will have the authority to develop and enforce reliability standards for the North American bulk electric system.

The formation of an ERO was authorized in the recent United States Energy Bill with provisions for the establishment of an agency with authority to enforce reliability standards. Whether NERC is successful or not in taking on this role, existing and forthcoming NERC standards will likely become the foundation for wind plant performance requirements in both the United States and Canada.

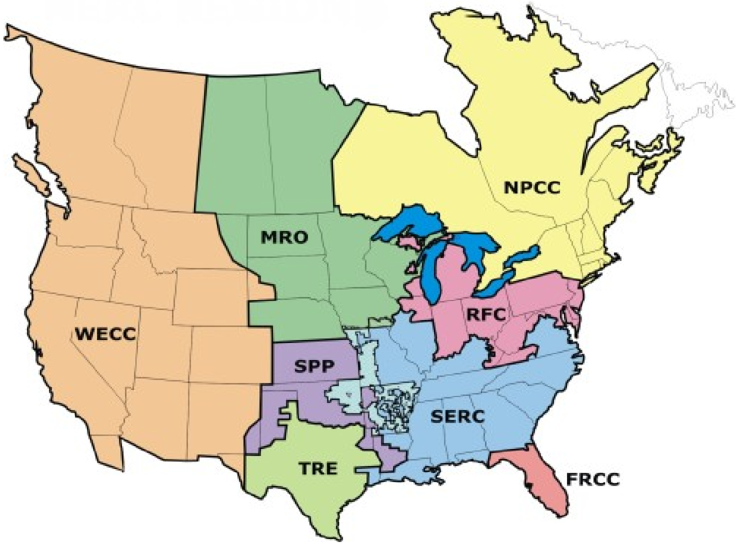


Figure 61. NERC regions

Their first order of business for the Wind Generation Task Force was to respond to the portions of FERC Order 2003a that laid out specific requirements for the interconnection of wind generation facilities. Concerning LVRT, NERC felt that the requirements proposed by AWEA were inadequate and contrary to the underlying principles for system reliability.

While NERC was generally supportive of the requirements being proposed as Appendix G at that time in the FERC proceeding, there was concern over whether the FERC process was the appropriate venue for addressing power system reliability issues. In addition, some expressed concern over certain details of both the LVRT and power factor requirements. Subsequent to the issuance of FERC Order 661[1], NERC filed a request for re-hearing on two aspects of the ruling:

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[1] 111 FERC 61,353; Unites States of America, Federal Energy Regulatory Commission; 18 CFR Part 35 (Docket No. RM-5-4-000 – Order No. 661) Interconnection for Wind Energy; Issued June 2, 2005

1. The LVRT requirement in Order 661, which in NERC's view should be modified to require that wind plants, like other generating facilities, be required to ride through a "normally cleared single line to ground or three phase fault on a transmission line connected to the (wind) plant switchyard or substation." This would have the effect that a wind plant be able to stay connected to the grid if the voltage at the high-side of the substation transformer were reduced to zero for a period up to about 0.15 s.
2. Placing the "burden of proof" for LVRT and reactive requirements on the transmission provider. NERC asserts that "(s)hifting the burden to transmission providers of justifying on a case-by-case basis what most regard as good utility practice is unwise."

As a result of the filing, both NERC and AWEA were ordered by the commission to work out a resolution to the dispute and report back. This process took place over the late summer 2005, culminating in a September 19, 2005, report[2] that recommended the following:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately four to nine cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to pre-fault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be nine cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.
2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g. Static

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[2] Joint Report of the North American Electric Reliability Council and the American Wind Energy Association, Docket No. RM05-4-000 (Sept. 19, 2005). ("NERC and AWEA proposal")

Var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

It was recommended that the standard be effective as of January 1, 2007. For a transition period that includes turbines purchased under a contract executed prior to December 31, 2005, for delivery through 2007, or turbines purchased for projects with interconnection agreements signed prior to December 31, 2006, a requirement in line with the Western Electricity Coordinating Council (WECC) standard of Figure 60. Adaptation of E.ON Netz Low Voltage Ride Through requirement for wind turbines, as proposed by AWEA for Appendix G of FERC Order 2003awould apply.

The FERC ruling was issued as Order No. 661a[3].

Notable in this recommendation is there is no specification of LVRT requirements after the fault, only the mandate that the plant and turbines not trip during the dynamic period in which the voltage is recovering to nominal.

In the negotiations with AWEA, NERC agreed that exceptions to this LVRT requirement should only be considered if they are made on an *interconnection-wide* basis. There are three interconnections in the United States and Canada: Western (WECC), ERCOT (Texas), and Eastern (everything else).

The agreement and subsequent FERC order does not restrict individual transmission providers from implementing a more stringent standard. However, to do so, it must make a case in a formal filing to FERC that such a deviation is necessary for system reliability. FERC will then consider the filing and solicit comments from the public. Such a process effectively prevents individual transmission providers from implementing a technically unnecessary requirement for the purpose of discriminating against wind generation.

LVRT requirements as agreed to in the NERC/AWEA negotiations will likely become the de-facto standard in the United States and Canada. In meeting this requirement, wind plants will be adhering to the same standard as all other types of large generation installations. Performance during the fault is well specified, and the current capabilities of the MWT1000A appear to be in compliance, especially for three-phase faults.

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[3] United States of America, Federal Energy regulatory Commission; 18 CFR Part 35 (Docket No. RM05-4-001; Order No. 661-A) Interconnection for Wind Energy, issued December 12, 2005.

The non-quantitative performance specified for the post fault period (must not trip) places additional emphasis on other plant design factors, especially in terms of reactive power compensation. The optimal reactive compensation for a wind plant with MWT1000A turbines will be quite specific to the plant layout and grid characteristics. When the strength of the grid interconnection relative to the plant rating is adequate, the issues for reactive compensation will generally be less difficult. A grid's short-circuit capacity to plant size ratio of 10 or more would characterize these situations. When the short circuit ratio falls below 10, reactive compensation issues for both steady state operations and response to grid events will become more acute. Such weak interconnections are not unheard of in the wind generation industry, as many good wind resource areas are remote from load centers where the grid capacity would tend to be higher. The Lamar, Colorado, plant, for example, may be one of the weakest wind plant interconnections to date. The short-circuit ratio at the point of interconnection for this plant is less than three.

3.6.8 Other Technology Trends

Reactive Power Control

Dynamic reactive power control is an important feature, and provides the plant designer with an additional tool for managing collector line voltage profiles within the plant and the overall reactive power characteristics of the plant. It should be recognized, however, that turbine-based reactive power control is not a "magic bullet", especially in cases where reactive power is required to support the transmission system, since in this situation the reactive power is being produced as far away as possible from where it is needed. The fast dynamic response of turbine-based reactive compensation may be very important, however, for assisting with system voltage recovery following faults.

To realize the full value for dynamic reactive power control, future wind turbines must be able to make reactive power available even when not generating.

Real Power Control

At present, commercial wind turbines generally operate to maximize energy production. When winds are at or above the rated speed, electrical output is "capped" at the nameplate rating. In light to moderate winds, however, the turbine is operated to capture as much energy as possible, such that the output will fluctuate when wind speed fluctuates.

These fluctuations are not optimal from the perspective of the grid, as they can lead to voltage variations and potentially increase the regulation burden at the control area level. In future generations of wind turbines, it will be possible to "smooth" these fluctuations to a greater degree than is achieved now with mechanical inertia alone. More sophisticated pitch regulation schemes, improved blade aerodynamic designs, and wider operating speed ranges will provide means for limiting the short-term changes in turbine output while at the same time minimizing the loss of production. Such a feature could only be enabled where and when it has economic value in excess of the lost production.

Extending this type of control would allow wind turbines to participate in Automatic Generation Control. In this mode, the turbine would have to operate at a level somewhat below the maximum available from the wind to provide room for “ramping up” in response to EMS commands. Again, the value of providing this service would have to be evaluated against the cost in terms of lower production as well as the cost of procuring this service from a different source. Technically, though, such operation is possible even with some of the present commercial wind turbine and wind plant technology.

Dynamic Performance

The dynamic characteristics of the more advanced commercial turbine technologies are complicated functions of the overall turbine design and control schemes. Little consideration has been given thus far to what would constitute desirable dynamic behavior from the perspective of the power system. Much of the attention to date in this area has been focused on the ride-through question. Once that matter is resolved, there may be opportunities to fine-tune the dynamic response of the turbine to transmission network faults so that it provides maximum support for system recovery and enhances overall stability.

Given the sophistication inherent in the topology and control schemes of future wind turbines, it should be possible to program the response to a degree to achieve such stability benefits. Such a feature would allow a wind turbine/wind plant to participate in a wide-area Remedial Action Scheme (RAS) or Special Protective System (SPS) as is sometimes done now with HVDC converter terminals and emerging FACTS devices.

Wind Plant Design and Operation

Realizing the benefits of enhanced capabilities of wind turbines will depend in large part on the overall wind plant design, since the actions of a large number of relatively small wind turbines must be coordinated to have positive impacts on the overall power system.

Reactive Power Management and Dispatch

Because of the fast pace at which the wind industry has emerged and grown over the last decade, the reactive power characteristics of a wind plant are more often an “outcome” rather than a design requirement. With more stringent interconnection requirements, more attention and analysis will be given to this topic for plants built over the next few years. The required reactive power capability of a wind plant will be determined from the results of the interconnection study, and will drive the overall wind plant design, possibly impacting even turbine selection.

Where the transmission system interconnection is weak or vulnerable, there will be more use of auxiliary equipment such as static var compensators. As design experience accumulates, the ability of the wind plant to provide for the needs of the transmission system at the point of interconnection will be much improved.

Communications and Control

The communications and control infrastructure of even present-day wind plants can be sophisticated, with high-speed SCADA to each turbine and other critical devices or points within the collector system. This sophisticated infrastructure has yet to be exploited for purposes of improving the interconnection performance and integration of the wind plant with the power system; mostly it has been used for maximizing plant production and availability.

In the future, this infrastructure will be the foundation upon which many of the advanced features and capabilities will be based. The interface between the wind plant control center and power system control area operations will also be developed to a much higher degree. Advanced wind plant performance such as AGC participation will likely be accomplished by the control area EMS interacting with the wind plant control center, rather than from EMS to individual wind turbines. Such an interface would also facilitate other plant capabilities that could benefit power system security and reliability, such as automatic full- or partial-curtailment of wind generation under severe system contingencies.

3.7 Task 7–Training Aids and Tools

The objective of this task was to define training tools and aids for SMUD operators based on data, methods, and results assembled for this research project.

The results of this research project will provide initial insights into the impact of significant wind generation on the operation of the SMUD control area, along with approaches for reducing or at least managing those impacts. From this starting point, it is likely that as the amount of wind generation increases, SMUD system operators and planners would, over time, develop increasingly better strategies for accommodating the unique nature of wind generation.

The data, methodology, and models assembled for this research project can be configured to provide value to SMUD operating personnel going forward. The high-resolution power system model developed for the Areva eterra-simulator DTS in Task 5.2 and the chronological wind generation data from Task 5.1 could serve as the foundation for a realistic operator training environment that could assist SMUD operators in developing strategies for managing increasing amounts of wind generation well before they are forced to confront such a challenge for real.

The need for such a training environment has not yet been established, and would depend at least in part on the results of this initial research project. Therefore, the actual development of the training system will not be pursued in this initial phase. Instead, effort will be expended to define, specify, and design the dispatch training platform for possible implementation at a later time.

In this task, the general framework for an operator training simulator for wind generation will be fleshed out through discussions and meetings with the appropriate

SMUD personnel. Interfacing the Areva DTS to SMUD's Energy Management System so that the training platform could provide screens and displays identical to what the operators currently use would most likely be a major requirement. As the project progresses, information concerning this cross-platform interface will be developed. Cost estimates for implementing the interface will also be generated.

The simulations and analysis conducted for this research project will also provide good indications of the situations and conditions–e.g. prior outages, load levels, patterns, etc.– that would present the most significant operational challenges for various levels of wind generation. This information will be used define an initial operator training curriculum, which will include descriptions of scenarios that could provide valuable insight and perspective for the operators.

Chapter 4:
Conclusions and Recommendations

4.1 Hourly Dispatch Simulations

The hourly dispatch simulations provided valuable awareness of the unit commitment behavior of the SMUD system. The cases run reflect the wide range of values that can be expected for integration cost based on wind penetration levels, treatment of reserve requirements, and forecast heading, among others.

In general, the unit commitment model used seems to do a very good job at penetration of 450 MW and below. At 850 MW, the simulations were left with substantial amounts of unserved and excess energy, which indicates that a feasible unit commitment and dispatch would be difficult at this wind level with the resources and market rules used.

Integration costs were seen to peak with the 250 MW case and decline with increasing wind penetration. The most significant factor is that the 250 MW case represents the poorest diversified case because the 250 MW are concentrated in one geographic location, maximizing the variability and effects of uncertainty. The overall variability and uncertainty are leveled when additional geographically dispersed areas are added, which reflects lower integration costs per unit of wind energy delivered.

The effect of increasing the reserve requirements for SMUD system is as expected, increasing both variable costs and the integration costs for wind. Carrying additional reserves for wind increases costs.

The proposed Iowa Hill pumped storage facility can lower the wind integration costs rather dramatically, by as much as $5/MWh under some conditions. As noted below in the “Next Steps” section, additional study of this case could likely improve this result by investigating alternative operating strategies.

The effect of the HASP sales is very important in these results, particularly in the discounted forecast cases. Substantial changes to the HASP model could influence the outcome significantly.

4.2 Next Steps

The hourly dispatch simulations task of this study represents a snapshot of best estimates of generation resources, forecast load conditions, and expected market rules. Each of these aspects can have a strong influence on the results of the operations, integration cost calculations, and the ultimate viability of the system with a given amount of integrated wind. For instance, the HASP sales are essential to the results of the cases run here. The amount and price of those sales strongly influence the outcome. The availability of an hour-ahead market for purchasing energy would also have major influence.

It is well known that wind forecast error strongly influences the outcome of wind integration cost calculations. This study did not include sensitivity analysis to the forecast error and how improved forecasting might affect the results. As state-of-the-art forecasting techniques improve the accuracy of those forecasts, better estimates of the operational and integration costs can be made.

This study did not model any possible correlation between wind and wind forecast error and load forecast error. There is empirical evidence that these wind forecast errors and load forecast errors are inversely related and additional analysis of this phenomena might be warranted.

This study included a brief investigation of hedging strategy against energy shortfalls due to lower wind than forecast. This was done by doing the day-ahead commitment with a severely discounted wind forecast. While this is effective against shortfalls, this drives up the wind integration costs as purchases are often considerably higher than necessary, particularly in summer. Additional investigations may yield an equally effective but less costly approach.

The case sets looking at the effects of the proposed Iowa Hill pumped storage facility were very limited in scope. Additional work investigating alternate operational models might yield more effective use of this facility and lead to lower operational and integration cost results.

Since this project began, gas prices have risen sharply and will not likely come back to the levels used in this analysis. Also, the analysis done here assumed a fixed gas price throughout the year. Future work should account for the new figures and allow fuel costs to vary at least on a seasonal, if not monthly, basis to give a more realist picture.

4.3 Benefits to California

The results of this project will provide initial insights into the impact of significant wind generation in the SMUD control area, along with approaches for reducing, or at least managing, those impacts. From this starting point, it is likely that as the amount of wind generation increases, SMUD system operators and planners would, over time, develop increasingly better strategies for accommodating the unique nature of wind generation.

The information gained in this study allows SMUD to evaluate wind generation expansion to meet its renewable portfolio goals while ensuring reliable and adequate energy delivery to its customers. SMUD planners now have an increased ability to determine the financial viability of wind generation projects. By being able to assess the whole picture (cost of production, integration, fast regulation requirement, effective capacity, etc.), the uncertainty of wind generation has been reduced.

Other utilities gain from the study by being able to replicate the methods used and utilize the results to better understand the effect of increasing wind generation on their control areas. This study was a necessary step toward increasing statewide wind generated electricity. Furthermore, the report gives electricity planners the information they need to provide renewable energy to their customers without compromising energy supply or reliability.

GLOSSARY

ACE	Area Control Error
AGC	Automatic Gain Control
AGC	Automation Generation Control
AWEA	American Wind Energy Association
DTS	Dispatcher Training Simulator
EENS	Expected Energy Not Supplied
ELCC	Equivalent Load Carrying Capacity
EMS	Energy Management System
ERO	Electric Reliability Authority
FERC	Federal Energy Regulatory Commission
FOR	Forced Outage Rate
GWh	Gigawatt-hour
Hz	Hertz
IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
Km	Kilometers
kW	Kilowatt
LOLD	Loss of Load Duration
LOLE	Loss of Load Expectation
LOLF	Loss of Load Frequency
LOLP	Loss of Load Probability
LVRT	Low Voltage Ride Through
M	Meters
MAE	Mean Absolute Error
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NREL	National Renewable Energy Laboratory
PIER	Public Interest Energy Research Program
PIRP	Participating Intermittent Resource Program
RAS	Remedial Action Scheme
Rpm	Revolutions per minute
SCADA	Supervisory Control and Data Acquisition
SMUD	Sacramento Municipal Utility District
SPS	Special Protective System
UARP	Upper Atmosphere Research Program
VRCC	Vestas Rotor Current Controller
WAPA	Western Area Power Association
WECC	Western Energy Coordinating Council